Q. MR. CHILES (PAGE 18) BELIEVES THAT SINCE THE POWER FLOW MODEL USED FOR DFAX AND FCITIC IS NOT THE SAME AS THE POWER FLOW MODEL USED IN THE PROMOD CASES, THE ANALYSIS MAY HAVE SOME GAPS. DO YOU AGREE?

A. No, I do not. Mr. Chiles misunderstands how reliability and market efficiency models are built and the constraints each model is designed to identify. The power flow model represents a snapshot of the transmission system for a specified generation and load pattern used to identify the capacity flow through the transmission system. The power flow model developed by SPP for the DISIS study was used by the Company to perform FCITC analysis in order to assess any adverse impacts to the *reliability* of the transmission system resulting from integrating resources assumed in SPP's DISIS Study. In contrast, the PROMOD model allows simulation of all hours in a year, not just one hour as in power flow models, and is designed to identify transmission congestion. The Company relied on the most recent PROMOD model available at the time of the study which was developed by SPP to identify transmission projects to address transmission congestion in their 2019 Integrated Transmission Planning (ITP) Assessment. The SPP PROMOD model was a reasonable starting point since assumptions of expected future system conditions were jointly developed by SPP and its stakeholders. To summarize, each model was designed for a specific purpose and they are valid models for the multiple tests performed by the Company to effectively evaluate bids and quantify benefits of the Selected Wind Facilities.

Q. MR. CHILES ALSO MADE SEVERAL RECOMMENDATIONS REGARDING THE DESIGN AND USE OF THE GEN-TIE, ASSERTING THEY ARE

NECESSARY FOR THE GEN-TIE TO "STAND THE RIGORS OF NERC TPL STANDARDS" (PAGE 15-16). HOW DO YOU RESPOND?

A. I do not agree with these recommendations and believe that they are unreasonable. Mr. Chiles argues that the Company's analysis should assume construction of the gen-tie in accordance with NERC Transmission Planning Standards and N-1 planning, which are used as foundational principles for planning *integrated* transmission systems. However, the gen tie's sole function would be to interconnect the Selected Wind Facilities to the SPP transmission system near Tulsa. A radial gen-tie connection is not a component of an integrated transmission system and the Company would not be required to meet such standards by either NERC or the SPP. An outage on the gen tie would affect only the Selected Wind Facilities, not the remainder of the system.

Mr. Chiles recommends installation of a second circuit on the gen tie or an additional parallel circuit, which he asserts would add an estimated $220 to $440 million[5] of costs to the gen-tie. This significant capital investment would not be a reasonable or prudent expenditure solely to eliminate the outage risk on the gen-tie. AEP's existing 345kV system historically has outages less than 1% of the year and, since the existing system is not new, this outage rate would likely be higher than the outage rate for a new 345kV gen-tie. The financial risk to customers from an outage on the gen-tie presumably would be even further limited by a new line because of the significant amount of customer value derived from the federal Production Tax Credit, which accrues only in the first 10 years of the project while the gen tie is new. Mr.

[5] Chiles Testimony, Page 16, line 21

Chiles' proposal to spend an additional $220-$440 million, not required by SPP or NERC standards, to relieve an outage risk of less than 1% that would only affect the Selected Wind Facilities is not reasonable.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

SPP Southwest Power Pool

INTERCONNECTION FACILITIES STUDY REPORT

GEN-2015-048

(IFS-2015-002-11)

Published March 2017

By SPP Generator Interconnections Dept.

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
2/1/2017	SPP	Initial draft report issued.	
3/17/2017	SPP	Initial final report issued.	

CONTENTS

SUMMARY

INTRODUCTION

This Interconnection Facilities Study (IFS) for Interconnection Request GEN-2015-048/IFS-2015-002-11 is for a 200.00 MW generating facility located in Major County, Oklahoma. The Interconnection Request was studied in the DISIS-2015-002 Impact Study for Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). Prior to an executed IFS agreement, the Interconnection Customer requested to withdraw NRIS per Section 4.4.1 of the Southwest Power Pool (SPP) Generator Interconnection Procedures (GIP), therefore ERIS-only was analyzed for this request in the DISIS-2015-002-1 Impact Restudy and DISIS-2015-002-2 Impact Restudy. The Interconnection Customer's requested in-service date is December 1, 2017.

The interconnecting Transmission Owner, Oklahoma Gas and Electric Company (OKGE), performed a detailed IFS at the request of SPP. The full report is included in Appendix A. SPP has determined that full Interconnection Service will be available after the assigned Transmission Owner Interconnection Facilities, Shared Network Upgrade(s), Non-Shared Network Upgrade(s), and Other Network Upgrade(s) are completed.

The primary objective of the IFS is to identify necessary Transmission Owner Interconnection Facilities, Network Upgrade(s), other direct assigned upgrade(s), and associated upgrade lead times needed to grant the requested Interconnection Service at the specified Point of Interconnection (POI).

PHASE(S) OF INTERCONNECTION SERVICE

It is not expected that Interconnection Service will occur in phases. However, Interconnection Service will not be available until all Interconnection Facilities and Network Upgrade(s) can be placed in service.

CREDITS/COMPENSATION FOR AMOUNTS ADVANCED FOR NETWORK UPGRADE(S)

Interconnection Customer shall be entitled to compensation in accordance with Attachment Z2 of the SPP OATT for the cost of SPP Network Upgrades, including any tax gross-up or any other tax-related payments associated with the Network Upgrades, that are not otherwise refunded to the Interconnection Customer. Compensation shall be in the form of either revenue credits or incremental Long Term Congestion Rights (iLTCR).

INTERCONNECTION CUSTOMER INTERCONNECTION FACILITIES

The Generating Facility is proposed to consist of one hundred (100) 2.0 MW Vestas wind generators for a total generating nameplate capacity of 200.00 MW.

The Interconnection Customer's Interconnection Facilities to be designed, procured, constructed, installed, maintained, and owned by the Interconnection Customer at its sole expense include:

- A 34.5kV collector system;
- One (1) 138/34.5kV 150/200/250 MVA (ONAN/ONAF/ONAF) step-up transformer to be owned and maintained by the Interconnection Customer at the Interconnection Customer's substation;
- A twenty (20) mile overhead 138kV line to connect the Interconnection Customer's substation to the POI at the 138 kV bus existing OKGE substation ("Cleo Corner") to be owned and maintained by OKGE;
- All transmission facilities required to connect the Interconnection Customer's substation to the POI;
- Equipment at the Interconnection Customer's substation necessary to maintain a power factor at the POI between 95% lagging and 95% leading, including approximately 20.3Mvars[1] of reactors to compensate for injection of reactive power into the transmission system under no/reduced generating conditions. The Interconnection Customer may use wind turbine manufacturing options for providing reactive power under no/reduced generation conditions. The Interconnection Customer will be required to provide documentation and design specifications demonstrating how the requirements are met.

The Interconnection Customer shall coordinate relay, protection, control, and communication system configurations and schemes with the Transmission Owner.

[1] This approximate minimum reactor amount is needed for the current configuration of the wind farm as studied in the DISIS-2015-002 Impact Study.

TRANSMISSION OWNER INTERCONNECTION FACILITIES AND NON-SHARED NETWORK UPGRADE(S)

To facilitate interconnection, the interconnecting Transmission Owner will perform work as shown below necessary for the acceptance of the Interconnection Customer's Interconnection Facilities.

Table 1 lists the Interconnection Customer's estimated cost responsibility for Transmission Owner Interconnection Facilities (TOIF) and Non-Shared Network Upgrade(s) and provides an estimated lead time for completion of construction. The estimated lead time begins when the Generator Interconnection Agreement has been fully executed.

Table 1: Interconnection Customer TOIF and Non-Shared Network Upgrade(s)

TOIF and Non-Shared Network Upgrades Description	Allocated Cost Estimate ($)	Allocated Percent (%)	Total Cost Estimate ($)	Estimated Lead Time
OKGE Cleo Corner Substation: Transmission Owner Interconnection Facilities 138kV Substation work for one (1) new line terminal, line switch, dead end structure, line relaying, communications, revenue metering, and line arrestor.	$410,000	100%	$410,000	10 Months
OKGE Cleo Corner Substation - Non-Shared Network Upgrades install four (4) 2000A circuit breakers, control panel replacement, line relaying, disconnect switches, and associated material and equipment. Reroute transmission line to the south to open up the north terminal.	$2,558,000	100%	$2,558,000	
Total	**$2,968,000**	**100%**	**$2,968,000**	

SHARED NETWORK UPGRADE(S)

The Interconnection Customer's share of costs for Shared Network Upgrades is estimated in **Table 2** below.

Table 2: Interconnection Customer Shared Network Upgrades

Shared Network Upgrades Description	Allocated Cost Estimate ($)	Allocated Percent (%)	Total Cost Estimate ($)
Cleo Corner - Cleo Plant Tap 138kV Circuit #1 Change CT tap setting and testing	$57,865	93.50	$61,890
Total	**$57,865**	**93.50**	**$61,890**

All studies have been conducted assuming that higher-queued Interconnection Request(s) and the associated Network Upgrade(s) will be placed into service. If higher-queued Interconnection Request(s) withdraw from the queue, suspend or terminate service, the Interconnection Customer's share of costs may be revised. Restudies, conducted at the customer's expense, will determine the Interconnection Customer's revised allocation of Shared Network Upgrades.

OTHER NETWORK UPGRADE(S)

Certain Other Network Upgrades are currently not the cost responsibility of the Interconnection Customer but will be required for full Interconnection Service.

1) Woodward - Tatonga - Mathewson 345kV circuit #2, assigned in 2012 Integrated Transmission Planning - 10 Year Assessment (ITP10). Currently on schedule for 7/1/2018 in-service.
2) Woodward EH Phase Shifting Transformer circuit #1 build, assigned to DISIS-2011-001 Interconnection Customer(s). Currently on schedule for 6/1/2017 in-service.

Depending upon the status of higher- or equally-queued customers, the Interconnection Request's in-service date is at risk of being delayed or Interconnection Service is at risk of being reduced until the in-service date of these Other Network Upgrades.

CONCLUSION

After all Interconnection Facilities and Network Upgrade(s) have been placed into service, Interconnection Service for 200.00 MW can be granted. Full Interconnection Service will be delayed until the Transmission Owner Interconnection Facilities, Shared Network Upgrade(s), Non-Shared Network Upgrade(s) and Other Network Upgrades are completed. The Interconnection Customer's estimated cost responsibility for Transmission Owner Interconnection Facilities, Non-Shared Network Upgrades, and Shared Network Upgrades is summarized in the table below.

Table 3: Cost Summary

Description	Allocated Cost Estimate
Transmission Owner Interconnection Facilities	$410,000
Network Upgrades	$2,615,865
Total	**$3,025,865**

A draft Generator Interconnection Agreement will be provided to the Interconnection Customer consistent with the final results of this IFS report. The Transmission Owner and Interconnection Customer will have 60 days to negotiate the terms of the GIA consistent with the SPP Open Access Transmission Tariff (OATT).

APPENDICES

SPP Southwest Power Pool

DISIS-2016-001-1

Definitive Interconnection System Impact Study Report

Published on 12/22/2017

By SPP Generator Interconnections Dept.

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
1/31/2017	SPP	Initial report issued.	Stability analysis has not been completed yet for groups 2, 6, 8, 9, & 16
2/8/2017	SPP	Report re-issued.	Added stand-alone results for all groups except 9, 15, and 16; stability results for groups 6 and 8. Final stand-alone and stability results are expected to be posted by Feb. 28, 2017.
2/28/2017	SPP	Report re-issued.	Reposted to include final revision 0 results
12/8/2017	SPP	DISIS-2016-001-1 Report revision 0 issued.	DISIS-2016-001-1 Report revision 0 results due to higher queued and equally queued withdrawals. Excludes stability results for group 9 expected to be posted by Dec. 22, 2017.
12/15/2017	SPP	Report revision 1 issued.	DISIS-2016-001-1 Report revision 1 results due cost allocation updates for Group 8. Group 6 stability final report revision to remove reference to 765kV.
12/22/2017	SPP	Report revision 2 issued.	DISIS-2016-001-1 Report revision 2 results for Group 9 stability, Group 8 LOIS correction, and Group 9 cost allocations based on latest TO information.

CONTENTS

1 INTRODUCTION

Pursuant to the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT), SPP has conducted this Definitive Interconnection System Impact Study (DISIS) for generation interconnection requests received during the DISIS Queue Cluster Window which closed on March 31, 2016. The customers will be referred to in this study as the DISIS Interconnection Customers. This DISIS analyzes the impact of interconnecting new generation totaling 7,656.45 MW to the SPP Transmission System. The interconnecting SPP Transmission Owners include:

- American Electric Power - West (AEPW)
- Basin Electric Power Cooperative (BEPC)
- The Empire District Electric Company (EMDE)
- Kansas City Power and Light Company\KCP&L Greater Missouri Operations Company (KCPL\KCPL-GMO)
- Midwest Energy, Inc. (MIDW)
- Nebraska Public Power District (NPPD)
- Oklahoma Gas and Electric Company (OKGE)
- Southwestern Public Service Company (SPS)
- Sunflower Electric Power Corporation\Mid-Kansas Electric Company, LLC. (SUNC\MKEC)
- Western Area Power Administration (WAPA)
- Westar Energy, Inc. (WERE)
- Western Farmers Electric Cooperative (WFEC)

The generation interconnection requests included in this System Impact Study are listed in Appendix A by queue number, amount, requested interconnection service type, area, requested interconnection point, proposed interconnection point, and the requested in-service date[1]. This cluster study represents the "Stand-Alone" analysis for remaining Interconnection Requests in the DISIS-2016-001 analysis.

Please note higher queued, MISO 2016-FEB-West Phase 2 analysis is not complete at this time. Depending on the results and mitigations assigned in MISO-2016-FEB-West Phase 2, SPP could require a restudy for Group 9, 15, 16, 17, and 18 due to higher queue study assumption changes.

The primary objective of this DISIS is to identify the system constraints, transient instabilities, and over-dutied equipment associated with connecting the generation to the area transmission system. The Impact Study and other subsequent Interconnection Studies are designed to identify required

[1] The generation interconnection requests in-service dates may need to be deferred based on the required lead time for the Network Upgrades necessary. The Interconnection Customers that proceed to the Facility Study will be provided a new in-service date based on the completion of the Facility Study or as otherwise provided for in the GIP.

Transmission Owner Interconnection Facilities, Network Upgrades and other Direct Assignment Facilities needed to inject power into the grid at each specific point of interconnection.

2 MODEL DEVELOPMENT (STUDY ASSUMPTIONS)

2.1 INTERCONNECTION REQUESTS INCLUDED IN THE CLUSTER

This DISIS includes all interconnection requests that were submitted during the DISIS Queue Cluster Window that met all of the requirements of the Generator Interconnection Procedures (GIP) that were in effect at the time this study commenced. Appendix A lists the interconnection requests that are included in this study.

2.2 AFFECTED SYSTEM INTERCONNECTION REQUEST

Affected System Interconnection Requests included in this study are listed in Appendix A with the "ASGI" prefix. Affected System Interconnection Requests were only studied in "cluster" scenarios.

2.3 PREVIOUSLY QUEUED INTERCONNECTION REQUESTS

The previous-queued requests included in this study are listed in Appendix B. In addition to the Base Case Upgrades, the previous-queued requests and associated upgrades were assumed to be in-service and added to the Base Case models. These requests were dispatched as Energy Resource Interconnection Service (ERIS) resources with equal distribution across the SPP footprint. Prior-queued requests that requested Network Resource Interconnection Service (NRIS) were also dispatched in separate NRIS scenarios sinking into the area of the interconnecting transmission owner.

2.4 DEVELOPMENT OF BASE CASES

2.4.1 POWER FLOW

The power flow models used for this study are based on the 2015-series Integrated Transmission Planning models used for the 2016 ITP-Near Term analysis. These models include:

- Year 1 2016 winter peak (16WP)
- Year 2 2017 spring (17G)
- Year 2 2017 summer peak (17SP)
- Year 5 2020 light load (20L)
- Year 5 2020 summer (20SP)
- Year 5 2020 winter peak (20WP)
- Year 10 2025 summer peak (25SP)

2.4.2 DYNAMIC STABILITY

The dynamic stability models used for this study are based on the 2015-series SPP Model Development Working Group (MDWG) Models. These models include:

- Year 1 2016 winter peak (16WP)
- Year 2 2017 summer peak (17SP)
- Year 5 2020 summer (20SP) (groups 6 & 16 only)
- Year 5 2020 winter peak (20WP) (groups 6 & 16 only)
- Year 10 2025 summer peak (25SP)

2.4.3 SHORT CIRCUIT

The Year 2 and Year 10 dynamic stability summer peak models were used for short-circuit analysis.

2.4.4 BASE CASE UPGRADES

The facilities listed in the table below are part of the current SPP Transmission Expansion Plan, the Balanced Portfolio, or recently approved Priority Projects. These facilities have an approved Notification to Construct (NTC) or are in construction stages and were assumed to be in-service at the time of dispatch and added to the base case models. The DISIS Interconnection Customers have not been assigned advancement costs for the projects listed below.

The DISIS Interconnection Customers' Generation Facilities in-service dates may need to be delayed until the completion of the following upgrades. In some cases, the in-service date is beyond the allowable time a customer can delay. In this case, the Interconnection Customer may move forward with Limited Operation or remain in the DISIS Queue for additional study cycles. If, for some reason, construction on these projects is discontinued, additional restudies will be needed to determine the interconnection needs of the DISIS Interconnection Customers.

SPP Notification to Construct (NTC) ID	Project Owner	Upgrade Name	Estimated Date of Upgrade Completion (EOC)
200223	OGE	Tatonga - Woodward District EHV 345 kV Ckt 2	7/1/2018
200223	OGE	Matthewson - Tatonga 345 kV Ckt 2	7/1/2018
200240	OGE	Chisholm - Gracemont 345 kV Ckt 1 (OGE)	3/1/2018
200255	AEP	Chisholm - Gracemont 345kV Ckt 1 (AEP)	3/1/2018
200255	AEP	Chisholm 345/230 kV Substation	3/1/2018
200255	AEP	Chisholm 230 kV	3/1/2018
200360	SPS	IMC #1 Tap - Livingston Ridge 115 kV Ckt 1 Rebuild	11/16/2018
200360	SPS	Intrepid West - Potash Junction 115 kV Ckt 1 Rebuild	11/16/2018
200360	SPS	IMC #1 Tap - Intrepid West 115 kV Ckt 1 Rebuild	11/16/2018
200360	SPS	Cardinal - Targa 115 kV Ckt 1 Rebuild	5/31/2018
200360	SPS	National Enrichment Plant - Targa 115 kV Ckt 1	8/15/2017
200391	OGE	DeGrasse 345 kV Substation	6/1/2017 (RTO Determined Need Date)
200391	OGE	DeGrasse 345/138 kV Transformer	6/1/2017 (RTO Determined Need Date)

SPP Notification to Construct (NTC) ID	Project Owner	Upgrade Name	Estimated Date of Upgrade Completion (EOC)
200391	OGE	DeGrasse - Knob Hill 138 kV New Line	6/1/2017 (RTO Determined Need Date)
200391	OGE	DeGrasse 138 kV Substation (OGE)	6/1/2017 (RTO Determined Need Date)
200220	NPPD	Cherry Co. (Thedford) - Gentleman 345 kV Ckt 1	10/1/2019
200220	NPPD	Cherry Co. (Thedford) Substation 345 kV	10/1/2019
200220	NPPD	Cherry Co. (Thedford) - Holt Co. 345 kV Ckt 1	10/1/2019
200220	NPPD	Holt Co. Substation 345 kV	10/1/2019
200253	NPPD	Neligh 345/115 kV Substation	6/1/2017
200309	SPS	Hobbs 345/230 kV Ckt 1 Transformer	6/1/2018
200309	SPS	Hobbs - Yoakum 345 kV Ckt 1	6/1/2020
200395	SPS	Tuco - Yoakum 345 kV Ckt 1	6/1/2020
200395	SPS	Yoakum 345/230 kV Ckt 1 Transformer	6/1/2020
200256	SPS	Chaves - Price 115 kV Ckt 1 Rebuild	12/30/2017
200256	SPS	CV Pines - Price 115 kV Ckt 1 Rebuild	12/30/2017
200256	SPS	Capitan - CV Pines 115 kV Ckt 1 Rebuild	12/30/2017
200282	SPS	China Draw - Yeso Hills 115 kV Ckt 1	6/1/2018
200282	SPS	Dollarhide - Toboso Flats 115 kV Ckt 1	6/1/2018
200309	SPS	Hobbs - Kiowa 345 kV Ckt 1	6/1/2018
200309	SPS	Kiowa 345 kV Substation	6/1/2018
200309	SPS	Kiowa - North Loving 345 kV Ckt 1	6/1/2018
200309	SPS	North Loving 345 kV Terminal Upgrades	6/1/2018
200309	SPS	China Draw - North Loving 345 kV Ckt 1	6/1/2018
200309	SPS	China Draw 345 kV Ckt 1 Terminal Upgrades	6/1/2018
200309	SPS	China Draw 345/115 kV Ckt 1 Transformer	6/1/2018
200309	SPS	North Loving 345/115 kV Ckt 1 Transformer	6/1/2018
200309	SPS	Kiowa 345/115 kV Ckt 1 Transformer	6/1/2018
200395	SPS	Livingston Ridge 115 kV Substation Conversion	8/31/2017
200411	SPS	Livingston Ridge - Sage Brush 115 kV Ckt 1	6/1/2018
200309	SPS	Sage Brush 115 kV Substation	12/16/2016
200309	SPS	Largarto - Sage Brush 115 kV Ckt 1	12/15/2016
200309	SPS	Lagarto 115 kV Substation	6/1/2018
200309	SPS	Cardinal - Lagarto 115 kV Ckt 1	12/15/2016
200309	SPS	Cardinal 115 kV Substation	12/15/2016
200411	SPS	Ponderosa - Ponderosa Tap 115 kV Ckt 1	6/1/2017
20097	TSMO	Sibley - Mullin Creek 345 kV	Placed in-service in 2016
20097	TSMO	Nebraska City - Mullin Creek 345 kV (GMO)	
20098	OPPD	Nebraska City - Mullin Creek 345 kV (OPPD)	
200395	SPS	Canyon West – Dawn – Panda – Deaf Smith 115kV Ckt 1	12/15/2018
200369	SPS	Canyon East Sub – Randall County Interchange 115kV Ckt 1	12/31/2020
200359	SPS	Carlisle 230/115kV transformer replacement	12/31/2017
200309	SPS	Hobbs – Yoakum – TUCO 345kV project	6/1/2018
200395	SPS	Terry County – Wolfforth 115kV Ckt 1 terminal equipment replacement	6/1/2018
200391	OGE	DeGrasse 345/138kV project	6/1/2017
200396	WFEC	DeGrasse 345/138kV project	6/1/2017
200395	SPS	Harrington East – Potter 230kV Ckt 1 terminal equipment replacement	6/1/2019
200228	WERE	Viola 345/138kV project	6/1/2018
200228	MKEC	Viola 345/138kV project	6/1/2018
200395	SPS	Seminole 230/115kV transformer Ckt 1 & 2 replacement	5/15/2018

SPP Notification to Construct (NTC) ID	Project Owner	Upgrade Name	Estimated Date of Upgrade Completion (EOC)
200262	SPS	Yoakum County Interchange 230/115kV transformer Ckt 1 & 2 replacement	6/1/2019

2.4.5 CONTINGENT UPGRADES

The following facilities do not yet have approval. These facilities have been assigned to higher-queued interconnection customers. These facilities have been included in the models for this study and are assumed to be in service. This list may not be all-inclusive. <u>The DISIS Interconnection Customers, at this time, do not have cost responsibility for these facilities but may later be assigned cost if higher-queued customers terminate their Generation Interconnection Agreement or withdraw from the interconnection queue. The DISIS Interconnection Customer Generation Facilities in-service dates may need to be delayed until the completion of the following upgrades.</u>

Assigned Study	Upgrade Name	Estimated Date of Upgrade Completion (EOC)
DISIS-2010-002	Twin Church - Dixon County 230kV Line Upgrade	11/1/2018
DISIS-2010-002	Buckner - Spearville 345 kV Ckt 1 Terminal Upgrades	12/31/2017
DISIS-2011-001	Hoskins - Dixon County 230kV Line Upgrade	11/1/2018
DISIS-2011-001	Woodward EHV 138kV Phase Shifting Transformer circuit #1	Placed in-service in 2017
DISIS-2013-002	Antelope - County Line - 115kV Rebuild	Placed in-service 2017
DISIS-2013-002	Battle Creek - County Line 115kV Rebuild	
DISIS-2014-002	Plant X - Tolk 230kV rebuild circuit #1	5/31/2018
DISIS-2014-002	Plant X - Tolk 230kV rebuild circuit #2	5/31/2018
DISIS-2014-002	TUCO Interchange 345/230kV CKT 1 Replacement	6/1/2018
DISIS-2015-001	Kress Interchange – Swisher 115kV circuit #1 replace terminal equipment.	TBD
DISIS-2015-001	Oklaunion 345kV Reactive Power Support Install two (2) 50Mvar Capacitor Bank(s)	TBD
DISIS-2015-001	(NRIS Only) Renfrow – Renfrow 138kV circuit #1 rebuild.	TBD
DISIS-2015-002	Potter County Interchange 345/230/13kV Transformer circuit #2, build.	TBD
DISIS-2015-002	Crawfish Draw Substation 345/230kV	TBD
DISIS-2015-002	Border - Chisholm 345kV CKT 1 & 2	TBD
DISIS-2015-002	Chisholm Substation Upgrade 345kV	TBD
DISIS-2015-002	Cleo Corner - Cleo Plant Tap 138kV CKT 1	TBD
DISIS-2015-002	Cleveland - Silver City 138kV CKT 1	TBD
DISIS-2015-002	Cornville Tap - Naples Tap 138kV CKT 1	TBD
DISIS-2015-002	Crawfish Draw - Border 345kV CKT 2	TBD
DISIS-2015-002	Dickinson 230/115/13.8kV CKT 2	TBD
DISIS-2015-002	Gavins Point - Yankton Junction 115kV CKT 1	TBD
DISIS-2015-002	GEN-2015-063 Tap - Mathewson 345kV CKT 1	TBD
DISIS-2015-002	Grapevine - Nichols 230kV CKT 1	TBD
DISIS-2015-002	Grapevine - Wheeler 230kV CKT 1	TBD
DISIS-2015-002	Naples Tap - Payne 138kV CKT 1	TBD
DISIS-2015-002	Norge - Southwest Station 138kV CKT 1	TBD

Assigned Study	Upgrade Name	Estimated Date of Upgrade Completion (EOC)
DISIS-2015-002	Albion - Petersburg - North Petersburg 115kV CKT 1	TBD
DISIS-2015-002	Wheeler - Sweetwater 230kV CKT 1	TBD

2.4.6 POTENTIAL UPGRADES NOT IN THE BASE CASE

Any potential upgrades that do not have a Notification to Construct (NTC) and are not explicitly listed within this report have not been included in the base case. These upgrades include any identified in the SPP Extra-High Voltage (EHV) overlay plan, or any other SPP planning study other than the upgrades listed above in the previous section.

2.4.7 REGIONAL GROUPINGS

The interconnection requests listed in Appendix A are grouped into fifteen (15) active regional groups based on geographical and electrical impacts. These groupings are shown in Appendix C.

To determine interconnection impacts, fifteen (15) different generation dispatch scenarios of the spring, summer, light, and winter base case models are developed to accommodate the regional groupings.

2.5 *DEVELOPMENT OF ANALYSIS CASES*

2.5.1 POWER FLOW

For Variable Energy Resources (VER) (solar/wind) in each power flow case, Energy Resource Interconnection Service (ERIS), is evaluated for the generating plants within a geographical area of the interconnection request(s) for the VERs dispatched at 100% nameplate of maximum generation. The VERs in the remote areas are dispatched at 20% nameplate of maximum generation. These projects are dispatched across the SPP footprint using load factor ratios.

Peaking units are not dispatched in the spring case, or in the "High VER" summer and winter peak cases. To study peaking units' impacts, the Year 1 winter peak and Year 2 summer peak, Year 5 summer and winter peaks, and Year 10 summer peak models are developed with peaking units dispatched at 100% of the nameplate rating and VERs dispatched at 20% of the nameplate rating. Each interconnection request is also modeled separately at 100% nameplate for certain analyses.

All generators (VER and peaking) that requested Network Resource Interconnection Service (NRIS) are dispatched in an additional analysis into the interconnecting Transmission Owner's (T.O.) area at 100% nameplate with Energy Resource Interconnection Service (ERIS) only requests at 80% nameplate. This method allows for identification of network constraints that are common between regional groupings to have affecting requests share the mitigating upgrade costs throughout the cluster.

The following additional sensitivities were run for situations specific to the local area.

- North Dakota – Canadian border – The phase shifting transformer to Saskatchewan Power (also known as B-10T) and Miles City DC Tie were dispatched at the following levels
    - 2016 Winter Peak –
        - Miles City DC Tie– 200MW East to West transfer
        - B-10T – 65MW South to North transfer
    - 2017 Summer Peak –
        - Miles City DC Tie – 200MW East to West transfer
        - B-10T – 200MW North to South transfer
    - Other Seasons
        - Miles City DC Tie – 140MW East to West transfer (20WP)
        - Miles City DC Ties – 92MW East to West transfer (17G & 20L)
        - B-10T – 0MW

2.5.2 DYNAMIC STABILITY

For each group, all interconnection requests are dispatched at 100% nameplate output while the other groups are dispatched at 20% output for VERs and 100% output for thermal requests.

- North Dakota – Canadian border – The phase shifting transformer to Saskatchewan Power (also known as B-10T) and Miles City DC Tie were dispatched at the following levels
  - 2016 Winter Peak –
    - Miles City DC Tie– 200MW East to West transfer
    - B-10T – 65MW South to North transfer
  - 2017 Summer Peak –
    - Miles City DC Tie – 200MW East to West transfer
    - B-10T – 200MW North to South transfer

2.5.3 SHORT CIRCUIT

The dynamic stability models are used for this analysis.

3 IDENTIFICATION OF NETWORK CONSTRAINTS (SYSTEM PERFORMANCE)

3.1 THERMAL OVERLOADS

Network constraints are found by using PSS/E AC Contingency Calculation (ACCC) analysis with PSS/E MUST First Contingency Incremental Transfer Capability (FCITC) analysis on the entire cluster grouping dispatched at the various levels previously described.

For Energy Resource Interconnection Service (ERIS), thermal overloads are determined for system intact (n-0) greater than 100% of Rate A - normal and for contingency (n-1) greater than 100% of Rate B – emergency conditions.

The overloads are then screened to determine which interconnection requests have at least

- 3% Distribution Factor (DF) for system intact conditions (n-0),
- 20% DF upon outage-based conditions (n-1),
- or 3% DF on contingent elements that resulted in a non-converged solution.

Appropriate transmission reinforcements are identified to mitigate the constraints.

Interconnection Requests that requested Network Resource Interconnection Service (NRIS) are also studied in a separate NRIS analysis to determine if any constraint measured greater than or equal to a 3% DF. If so, these constraints are also assigned transmission reinforcements to mitigate the impacts.

3.2 VOLTAGE

For non-converged power flow solutions that are determined to be caused by lack of voltage support, appropriate transmission support will be identified to mitigate the constraint.

After all thermal overload and voltage support mitigations are determined; a full ACCC analysis is then performed to determine voltage constraints. The following voltage performance guidelines are used in accordance with the Transmission Owner local planning criteria.

SPP voltage criteria are applicable to all SPP facilities 69 kV and greater in the absence of more stringent criteria:

System Intact	Contingency
0.95 – 1.05 per unit	0.90 – 1.05 per unit

Areas and specific buses having more-stringent voltage criteria:

Areas/Facilities	System Intact	Contingency
AEPW – all buses EMDE High Voltage	0.95 – 1.05 per unit	0.92 – 1.05 per unit
WERE Low Voltage	0.95 – 1.05 per unit	0.93 – 1.05 per unit
WERE High Voltage	0.95 – 1.05 per unit	0.95 – 1.05 per unit
TUCO 230 kV Bus #525830	0.925 – 1.05 per unit	0.925 – 1.05 per unit
Wolf Creek 345 kV Bus #532797	0.985 – 1.03 per unit	0.985 – 1.03 per unit
S1251 Bus #646251	1.001 – 1.047 per unit	1.001 – 1.047 per unit

First-Tier External Areas facilities 115 kV and greater.

Area	System Intact	Contingency
AECI EES-EAI LAGN EES AMMO CLEC LAFA LEPA XEL MP SMMPA GRE OTP ALTW MEC MDU DPC ALTE	0.95 – 1.05 per unit	0.90 – 1.05 per unit
OTP-H (115kV+)	0.97 – 1.05 per unit	0.92 – 1.10 per unit
SPC	0.95 – 1.05 per unit	0.95 – 1.05 per unit

The constraints identified through the voltage scan are screened for the following for each interconnection request. 1) 3% DF on the contingent element and 2) 2% change in pu voltage. In certain conditions, engineering judgement was used to determine whether or not a generator had impacts to voltage constraints.

3.3 DYNAMIC STABILITY

Stability issues are considered for transmission reinforcement under ERIS. Generators that fail to meet low voltage ride-through requirements (FERC Order #661-A) or SPP's stability criteria for damping or dynamic voltage recovery are assigned upgrades such that these requirements can be met.

3.4 UPGRADES ASSIGNED

Thermal overloads that require transmission support to mitigate are discussed in Section 8 and listed in Appendix G-T (Cluster & Stand Alone Analysis). Voltage constraints that may require transmission support are discussed in Section 8 and listed in Appendix G-V (Cluster & Stand Alone Analysis). Constraints that are identified solely through the stability analysis are discussed in Section 8 and the appropriate appendix for the detailed stability study of that Interconnection Request. All of these upgrades are cost assigned in Appendix E and Appendix F.

Other network constraints not requiring transmission reinforcements are shown in Appendix H-T (Cluster & Stand Alone Analysis). With a defined source and sink in a Transmission Service Request, this list of network constraints can be refined and expanded to account for all Network Upgrade requirements for firm transmission service. Additional constraints identified by multi-element contingencies are listed in Appendix I.

In no way does the list of constraints in Appendix G-T (Cluster & Stand Alone Analysis) identify all potential constraints that guarantee operation for all periods of time. It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list and cannot account for every operational situation. Because of this, it is likely that the Customer(s) may be required to reduce their generation output to 0 MW, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

4 DETERMINATION OF COST ALLOCATED NETWORK UPGRADES

Cost Allocated Network Upgrades of Variable Energy Resources (VER) (solar/wind) generation interconnection requests are determined using the Year 2 spring model. Cost Allocated Network Upgrades of peaking units are determined using the Year 5 summer peak model. A PSS/E and MUST sensitivity analysis is performed to determine the Distribution Factors (DF), a distribution factor with no contingency that each generation interconnection request has on each new upgrade. The impact each generation interconnection request has on each upgrade project is weighted by the size of each request. Finally the costs due by each request for a particular project are then determined by allocating the portion of each request's impact over the impact of all affecting requests.

For example, assume that there are three Generation Interconnection requests, X, Y, and Z that are responsible for the costs of Upgrade Project '1'. Given that their respective PTDF for the project have been determined, the cost allocation for Generation Interconnection request 'X' for Upgrade Project 1 is found by the following set of steps and formulas:

Determine an impact factor for a given project for all responsible GI requests:

$$Request\ X\ Impact\ Factor\ on\ Upgrade\ Project\ 1 = PTDF(\%)(X) \times MW(X) = X1$$

$$Request\ Y\ Impact\ Factor\ on\ Upgrade\ Project\ 1 = PTDF(\%)(Y) \times MW(Y) = Y1$$

$$Request\ Z\ Impact\ Factor\ on\ Upgrade\ Project\ 1 = PTDF(\%)(Z) \times MW(Z) = Z1$$

Determine each request's Allocation of Cost for that particular project:

$$Request\ X's\ Project\ 1\ Cost\ Allocation\ (\$) = \frac{Network\ Upgrade\ Project\ 1\ Cost\ (\$) \times X1}{X1 + Y1 + Z1}$$

Repeat previous for each responsible GI request for each Project.

The cost allocation of each needed Network Upgrade is determined by the size of each request and its impact on the given project. This allows for the most efficient and reasonable mechanism for sharing the costs of upgrades.

4.1 CREDITS/COMPENSATION FOR AMOUNTS ADVANCED FOR NETWORK UPGRADES

Interconnection Customer shall be entitled to either credits or potentially incremental Long Term Congestion Rights (iLTCR), otherwise known as compensation, in accordance with Attachment Z2 of the SPP Tariff for any Network Upgrades, including any tax gross-up or any other tax-related payments associated with the Network Upgrades, and not refunded to the Interconnection Customer[2].

5 REQUIRED INTERCONNECTION FACILITIES

The requirement to interconnect the requested generation into the existing and proposed transmission systems in the affected areas of the SPP transmission footprint consist of the necessary cost allocated shared facilities listed in Appendix F by upgrade. The interconnection requirements for the cluster total an estimated $1.4 billion, not including the following costs.

- **Costs Not Included** – Potential additional upgrades required based on review of Laramie Generation Station (LGS) stability limit in southeastern Wyoming. LGS stability limit is to be analyzed by BEPC as part of the Interconnection Facilities Study.
- **Costs Not Included** – Potential additional upgrades required based on review of Gerald Gentleman Station (GGS) stability interface in western Nebraska. GGS stability interface is to be analyzed by NPPD as part of the Interconnection Facilities Study.
- **Costs Not Included** – Costs on Mid-Continent Independent System Operator (MISO).
- **Costs Not Included** –Particular Interconnection Facilities observing instability in the transient stability analysis due to Interconnection Facilities configuration or Interconnection Customer provided dynamic model settings and parameters. Please refer to Appendix E for requests that are identified as requiring further review or costs for Interconnection Facilities.

Interconnection Facilities specific to each interconnection request are listed in Appendix E. A preliminary one-line diagram for each request is listed in Appendix D.

For an explanation of how required Network Upgrades and Interconnection Facilities were determined, refer to the section on "Identification of Network Constraints."

5.1 FACILITIES ANALYSIS

The interconnecting Transmission Owner for each Interconnection Request has provided its preliminary analysis of required Transmission Owner Interconnection Facilities and the associated Network Upgrades, shown in Appendix D. This analysis was limited only to the expected facilities to be constructed by the Transmission Owner at the Point of Interconnection. These costs are included in the one-line diagrams in Appendix D and also listed in Appendix E and F as combined "Interconnection Costs". If the one-lines and costs in Appendix D have been updated by the

[2] A FERC filing is pending in Docket No. ER18-374 to change the provisions of Attachment Z2 which may result in certain upgrades no longer being eligible for revenue credits.

Transmission Owner's Interconnection Facilities Study, those costs will be noted in the appendix. These costs will be further refined by the Transmission Owner as part of the Interconnection Facilities Study. Any additional Network Upgrades identified by this DISIS beyond the Point of Interconnection are defined and estimated by either the Transmission Owner or by SPP. These additional Network Upgrade costs will also be refined further by the Transmission Owner within the Interconnection Facilities Study.

5.2 ENVIRONMENTAL REVIEW

For Interconnection Requests that result in an interconnection to, or modification to, the transmission facilities of the Western-UGP, a National Environmental Policy Act (NEPA) Environmental Review will be required. The Interconnection Customer will be required to execute an Environmental Review Agreement per Section 8.6.1 of the GIP.

6 AFFECTED SYSTEMS COORDINATION

The following procedures are in place to coordinate with Affected Systems.

- Impacts on Associated Electric Cooperative Inc. (AECI) – For any observed violations of thermal overloads on AECI facilities, AECI has been notified by SPP to evaluate the violations for impacts on its transmission system. AECI has instructed SPP to notify the affected Interconnection Customers after posting of this study to contact AECI for an Affected System Study Agreement to further study the impacts on the AECI system.
- Impacts on Mid Continent Independent System Operation (MISO) – Per SPP's agreement with MISO, MISO will be contacted and provided a list of interconnection requests that proceed to move forward into the Interconnection Facilities Study Queue. MISO will then evaluate the Interconnection Requests for impacts and will be in contact with affected Interconnection Customers. For potential impacts see Appendix H-T – Affected System and Appendix H-V – Affected System
- Impacts on Minnkota Power Cooperative, Inc (MPC) – MPC Report is located in Appendix H-AS-T.
- Impacts to other affected systems – For any observed violations of thermal overloads or voltage constraints, SPP will contact the owner of the facility for further information.

7 POWER FLOW ANALYSIS

7.1 POWER FLOW ANALYSIS METHODOLOGY

The ACCC function of PSS/E is used to simulate single element and special (i.e., breaker-to-breaker, multi-element, etc.) contingencies in portions or all of the modeled control areas of SPP, as well as, other control areas external to SPP and the resulting scenarios analyzed. Single element and multi-element contingencies are evaluated.

7.2 POWER FLOW ANALYSIS

A power flow analysis is conducted for each Interconnection Customer's facility using modified versions of the Year 1 winter peak season, the Year 2 spring, Year 2 summer peak season, Year 5 summer and winter peak seasons, and Year 10 summer peak seasonal models. The output of the Interconnection Customer's facility is offset in each model by a reduction in output of existing online SPP generation. This method allows the request to be studied as an Energy Resource Interconnection Service request (ERIS). Certain requests that are also pursuing Network Resource Interconnection Service (NRIS) have an additional analysis conducted for displacing resources in the interconnecting Transmission Owner's balancing area.

8 POWER FLOW RESULTS

8.1 CLUSTER SCENARIO

The Cluster Scenario considers the Base Case as well as all Interconnection Requests in the DISIS Study Queue and all generating facilities (and with respect to (3) below, any identified Network Upgrades associated with such higher-queued interconnection) that, on the date the DISIS is commenced:

1. are directly connected to the Transmission System;
2. are interconnection to Affected Systems and may have an impact on the Interconnection Request;
3. have a pending higher-queued Interconnection Request to interconnect to the Transmission System; and
4. have no Interconnection Queue Position but have executed a GIA or requested that an unexecuted GIA be filed with FERC.

Constraints and associated mitigations for each Interconnection Request are summarized below. Details are contained in Appendix G-T and Appendix G-V. Cost allocation for the Cluster Scenario is found in Appendix E.

8.1.1 CLUSTER GROUP 1 (WOODWARD AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

Several ERIS thermal were observed for system-intact and single-contingency (N-1) conditions. The tables below summarizes constraints and associated mitigations.

Table 8.1 Group 1 Cluster ERIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
CIMARRON - DRAPER LAKE 345KV CKT 1	717	104.8577	System Intact	Previously Assigned per SPP-NTC-200416
DGRASSE4 138.00 - ROSE_VALLEY 138.00 138KV CKT 1	143.0	165.2136	System Intact	DeGrasse 345/138kV Project (SPP-NTC-200418 & 200419)
DGRASSE4 138.00 - ROSE_VALLEY 138.00 138KV CKT 1	187.0	139.4533	WOODWARD EHV - WWPAR4 138.00 138KV CKT 1	
FPL SWITCH - WOODWARD 138KV CKT 1	153.0	112.0593	DGRASSE4 138.00 - ROSE_VALLEY 138.00 138KV CKT 1	
NOEL_SW 138.00 - ROSE_VALLEY 138.00 138KV CKT 1	200.0	111.1773	System Intact	
NOEL_SW 138.00 - ROSE_VALLEY 138.00 138KV CKT 1	234.0	105.2112	WOODWARD EHV - WWPAR4 138.00 138KV CKT 1	

The table below summarizes constraints and associated mitigations assignable to incremental ERIS steady state voltage.

GEN-2016-045 and GEN-2016-057 will require the installation of reactors for mitigation of high voltage constraints. Additionally GEN-2016-045 and GEN-2016-057 will be required to complete an Electro-Magnetic Transient Program (EMTP) study.

Table 8.2 Group 1 Cluster ERIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
GEN-2016-045345.00 345KV	1.322582	0.95	1.05	System Intact	GEN-2016-045 & GEN-2015-057 assigned reactors
GEN-2016-045345.00 345KV	1. 347816	0.95	1.05	MATHWSN7 345.00 - NORTHWEST 345KV CKT 1	
MATHWSN7 345.00 345KV	1.060389	0.90	1.05	TATONGA7 345.00 - WOODWARD DISTRICT EHV 345KV CKT 1	

The table below summarizes constraints and associated mitigations assignable to those requests that elect NRIS.

Table 8.3 Group 1 Cluster NRIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
Currently none				

The table below summarizes constraints and associated mitigations assignable to incremental NRIS steady state voltage.

Table 8.4 Group 1 Cluster NRIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Currently none					

8.1.2 CLUSTER GROUP 2 (HITCHLAND AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

Several ERIS thermal constraints were observed for system-intact and single-contingency (N-1) conditions. The table below summarizes constraints and associated mitigations. The table below summarizes constraints and associated mitigations. Potential voltage collapse is inferred from non-convergence.

Table 8.5 Group 2 Cluster ERIS Thermal Constraints

	Contingency			Mitigation
ASARCO_TP 3115.00 - HIGHLAND PARK TAP 115KV CKT 1	154.0	101.7136	HUTCHINSON COUNTY INTERCHANGE S. - MARTIN SUB 115KV CKT 1	Updated rating is sufficient for mitigation
BUSHLAND INTERCHANGE - POTTER COUNTY INTERCHANGE 230KV CKT 1	318.7	114.3733	System Intact	Previously assigned in DISIS-2015-002-4 to replace terminal equipment
HIGHLAND PARK TAP - PANTEX SOUTH SUB 115KV CKT 1	154.0	108.7758	HUTCHINSON COUNTY INTERCHANGE S. - MARTIN SUB 115KV CKT 1	Previously assigned per SPP-NTC-200444 to replace terminal equipment
MARTIN SUB - PANTEX NORTH SUB 115KV CKT 1	160.0	104.4728	HUTCHINSON COUNTY INTERCHANGE S. - MARTIN SUB 115KV CKT 1	
SPSNORTH_STX	1160.0	102.5864	System Intact Flowgate	Updated flowgate rating is sufficient for mitigation

The table below summarizes constraints and associated mitigations assignable to incremental ERIS steady state voltage.

Table 8.6 Group 2 Cluster ERIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Currently none that are incremental to thermal mitigations					

The table below summarizes constraints and associated mitigations assignable to those requests that elect NRIS.

Table 8.7 Group 2 Cluster NRIS Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
Currently none				

The table below summarizes constraints and associated mitigations assignable to incremental NRIS steady state voltage.

Table 8.8 Group 2 Cluster NRIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Currently none that are incremental to thermal mitigations					

8.1.3 CLUSTER GROUP 3 (SPEARVILLE AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

Several ERIS thermal and voltage constraints were observed for system-intact and single-contingency (N-1) conditions. The table below summarizes constraints and associated mitigations. The table below summarizes constraints and associated mitigations. Potential voltage collapse is inferred from non-convergence.

Table 8.9 Group 3 Cluster ERIS Non-Convergence Constraints

Contingency	Mitigation
BUCKNER7 345.00 - HOLCOMB 345KV CKT 1	Build 125 miles of new 345kV from Beaver County - Clark County
FINNEY SWITCHING STATION - Hitchland Interchange 345KV CKT 1	
FINNEY SWITCHING STATION - WALKTAP7 345.00 345KV CKT 1	
G13-010T 345.00 - G16-049-TAP 345.00 345KV CKT 1	
G13-010T 345.00 - POST ROCK 345KV CKT 1	
Hitchland Interchange - WALKTAP7 345.00 345KV CKT 1	
P12:345:SPS:J07.1.FINN.HITCH	

Table 8.10 Group 3 Cluster ERIS Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
CLEARWATER - MILAN TAP 138KV CKT 1	110.0	118.2928	System Intact	Viola 345/138 Project and HPILS Project (NTC)
CONWAY 138.00 - MILAN TAP 138KV CKT 1	100.6	129.1001	System Intact	
CONWAY 138.00 - VIOLA 4 138.00 138KV CKT 1	100.6	128.9764	System Intact	
HARPER - MILAN TAP 138KV CKT 1	138.6	101.8611	System Intact	
KINSLEY - PAWNEE-EDWARDS_JCT 115KV CKT 1	76	99.3	System Intact	Conductor clearance increase
KNOLL 230 - POSTROCK6 230.00 230KV CKT 1	328.0	104.3921	System Intact	Previously assigned build second Knoll – Post Rock 230kV per SPP-NTC-200429 and current study assigned build 125 miles of new 345kV from Beaver County - Clark County
POST ROCK (POSTROCK T1) 345/230/13.8KV TRANSFORMER CKT 1	600.0	102.0037	AXTELL - G16-050-TAP 345.00 345KV CKT 1	Build 125 miles of new 345kV from Beaver County - Clark County

The table below summarizes constraints and associated mitigations assignable to incremental ERIS steady state voltage.

Table 8.11 Group 3 Cluster ERIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Currently none that are incremental to thermal mitigations					

The table below summarizes constraints and associated mitigations assignable to those requests that elect NRIS.

Table 8.12 Group 3 Cluster NRIS Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
None in addition to ERIS constraints				

The table below summarizes constraints and associated mitigations assignable to incremental NRIS steady state voltage.

Table 8.13 Group 3 Cluster NRIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Currently none that are incremental to ERIS thermal or non-convergence mitigations					

8.1.4 CLUSTER GROUP 4 (NORTHWEST KANSAS AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C. No new constraints were observed for this group.

Table 8.14 Group 4 Cluster ERIS Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
Currently none				

The table below summarizes constraints and associated mitigations assignable to incremental ERIS steady state voltage.

Table 8.15 Group 4 Cluster ERIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Currently none that are incremental to thermal mitigations					

The table below summarizes constraints and associated mitigations assignable to those requests that elect NRIS.

Table 8.16 Group 4 Cluster NRIS Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
Currently none				

The table below summarizes constraints and associated mitigations assignable to incremental NRIS steady state voltage.

Table 8.17 Group 4 Cluster NRIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Currently none that are incremental to ERIS thermal mitigations					

8.1.5 CLUSTER GROUP 6 (SOUTH TEXAS PANHANDLE/NEW MEXICO AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

Several ERIS thermal and voltage constraints were observed for system-intact and single-contingency (N-1) conditions. The table below summarizes non-convergence and thermal constraints and associated mitigations. The table below summarizes constraints and associated mitigations. Potential voltage collapse is inferred from non-convergence. Reactive power at Border and Oklaunion was required to dispatch the study models. Once models were reviewed after ACCC, the reactive power included in the dispatched cases were reviewed for evaluation of current study upgrade requirements. Crawfish Draw – Tolk – Potter County – Chisholm 345kV and Oklaunion reactive power support was required light load conditions to dispatch the DISIS-2016-001 Group 6 generation.

Table 8.18 Group 6 Cluster ERIS Non-Convergence Constraints

Contingency	Mitigation
917X	In addition to DISIS-2014-002, DISIS-2015-001, and DISIS-2015-002 assigned upgrades, the following new upgrades are required for group 6 potential voltage collapse: 1) Oklaunion +/-100Mvar SVC 2) Border +300Mvar SVC and 300Mvars of capacitor bank(s) 3) Build approximately 64 miles of new 345kV from Crawfish Draw – Tolk 4) Build approximately 115 miles of new 345kV from Tolk – Potter County
AMARILLO SOUTH INTERCHANGE - G15031_T 230.00 230KV CKT 1	
AMARILLO SOUTH INTERCHANGE - NICHOLS STATION 230KV CKT 1	
AXTELL - G16-050-TAP 345.00 345KV CKT 1	
BORDER 7345.00 - CHISHOLM7 345.00 345KV CKT 1	
BORDER 7345.00 - CHISHOLM7 345.00 345KV CKT 2	
BORDER 7345.00 - CRAWFISH_DR 345.00 345KV CKT 1	
BORDER 7345.00 - CRAWFISH_DR 345.00 345KV CKT 2	
BORDER 7345.00 - WOODWARD DISTRICT EHV 345KV CKT 1	
BUCKNER7 345.00 - HOLCOMB 345KV CKT 1	
BUCKNER7 345.00 - SPEARVILLE 345KV CKT 1	
BUSHLAND INTERCHANGE - DEAF SMITH COUNTY INTERCHANGE 230KV CKT 1	
BUSHLAND INTERCHANGE - POTTER COUNTY INTERCHANGE 230KV CKT 1	
BUSHLAND INTERCHANGE 230KV SWITCHED SHUNT	
BVRCNTY7 345.00 - G11-14T 345.00 345KV CKT 1	
BVRCNTY7 345.00 - G11-14T 345.00 345KV CKT 2	
BVRCNTY7 345.00 - OPTIMA 345.00 345KV CKT 1	
BVRCNTY7 345.00 - OPTIMA 345.00 345KV CKT 2	
CANYON E_TP3115.00 - CANYON WEST SUB 115KV CKT 1	
CANYON E_TP3115.00 - RANDALL COUNTY INTERCHANGE 115KV CKT 1	
CANYON WEST SUB - DAWN SUB 115KV CKT 1	
CARGILL SUB - DEAF SMITH REC-#24 115KV CKT 1	
CARLISLE INTERCHANGE - TUCO INTERCHANGE 230KV CKT 1	
CHAVES COUNTY INTERCHANGE - EDDY_NORTH 6230.00 230KV CKT 1	
CHERRY1 - HARRINGTON STATION 230KV CKT 1	
CHERRY1 - POTTER COUNTY INTERCHANGE 230KV CKT 1	
CHISHOLM6 230.00 - ELK CITY 230KV 230KV CKT 1	
CHISHOLM6 230.00 - SWEETWATER 230KV CKT 1	
CHISHOLM7 345.00 - G16-037-TAP 345.00 345KV CKT 1	
CIMARRON - DRAPER LAKE 345KV CKT 1	
CIMARRON - MINCO 345KV CKT 1	
CRAWFISH_DR 345.00 - TUCO INTERCHANGE 345KV CKT 1	
CRAWFISH_DR 345.00 (CRAWFISH_DR) 345/230/13.2KV TRANSFORMER CKT 1	
CRAWFISH_DR2230.00 - SWISHER COUNTY INTERCHANGE 230KV CKT 1	
CRAWFISH_DR2230.00 - TUCO INTERCHANGE 230KV CKT 1	
CROSSROADS 7345.00 - TOLK STATION 345KV CKT 1	
CURRY COUNTY INTERCHANGE - DEAF SMITH REC-#20 115KV CKT 1	

Contingency	Mitigation
DAWN SUB - Panda Energy Substation Hereford 115KV CKT 1	
DEAF SMITH COUNTY INTERCHANGE - Panda Energy Substation Hereford 115KV CKT 1	
DEAF SMITH COUNTY INTERCHANGE - PLANT X STATION 230KV CKT 1	
DEAF SMITH REC-#20 - PARMER COUNTY SUB 115KV CKT 1	
DEAF SMITH REC-#24 - PARMER COUNTY SUB 115KV CKT 1	
EDDY COUNTY INTERCHANGE - EDDY_NORTH 6230.00 230KV CKT @1	
ELK CITY 230KV (ELKCTY-6) 230/138/13.8KV TRANSFORMER CKT 1	
FINNEY SWITCHING STATION - Hitchland Interchange 345KV CKT 1	
FINNEY SWITCHING STATION - HOLCOMB 345KV CKT 1	
G11-14T 345.00 - G16-003-TAP 345.00 345KV CKT 1	
G11-14T 345.00 - G16-003-TAP 345.00 345KV CKT 2	
G13-010T 345.00 - POST ROCK 345KV CKT 1	
G14-057T 345.00 - LAWTON EASTSIDE 345KV CKT 1	
G14-057T 345.00 - SUNNYSIDE 345KV CKT 1	
G15031_T 230.00 - SWISHER COUNTY INTERCHANGE 230KV CKT 1	
G15079_T 230.00 - YOAKUM COUNTY INTERCHANGE 230KV CKT 1	
G1524G1525 345.00 - THISTLE7 345.00 345KV CKT 1	
G1524G1525 345.00 - THISTLE7 345.00 345KV CKT 2	
G16-003-TAP 345.00 - WOODWARD DISTRICT EHV 345KV CKT 1	
G16-003-TAP 345.00 - WOODWARD DISTRICT EHV 345KV CKT 2	
G16-037-TAP 345.00 - GRACEMONT 345KV CKT 1	
G16-049-TAP 345.00 - SPEARVILLE 345KV CKT 1	
G16-050-TAP 345.00 - POST ROCK 345KV CKT 1	
GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1	
GRACEMONT - MINCO 345KV CKT 1	
GRAPEVINE INTERCHANGE - NICHOLS STATION 230KV CKT 1	
GRAPEVINE INTERCHANGE - STATELINE INTERCHANGE 230KV CKT 1	
Hansford County Switch Station - SPEARMAN INTERCHANGE 115KV CKT 1	
Harrington Station East Bus - POTTER COUNTY INTERCHANGE 230KV CKT 1	
HITCHLAND INTERCHANGE - Hansford County Switch Station 115KV CKT 1	
HITCHLAND INTERCHANGE - MOORE COUNTY INTERCHANGE 230KV CKT 1	
Hitchland Interchange - POTTER COUNTY INTERCHANGE 345KV CKT 1	
Hitchland Interchange - WALKTAP7 345.00 345KV CKT 1	
Hitchland Interchange (H TB80155502) 345/230/13.2KV TRANSFORMER CKT 1	
Hitchland Interchange (SIEM 8743067) 345/230/13.2KV TRANSFORMER CKT 2	
HOBBS - YOAKUM_345 345.00 345KV CKT 1	
HOBBS (UPDATE DATA) 345/230/13.2KV TRANSFORMER CKT 1	
HOLCOMB - SETAB 345KV CKT 1	
JOHNSON COUNTY - SUNNYSIDE 345KV CKT 1	
JONES STATION - TUCO INTERCHANGE 230KV CKT 1	
LUBBOCK SOUTH INTERCHANGE - WOLFFORTH INTERCHANGE 230KV CKT 1	
MATHWSN7 345.00 - TATONGA7 345.00 345KV CKT 1	
MATHWSN7 345.00 - TATONGA7 345.00 345KV CKT 2	
MINGO - RED WILLOW 345KV CKT 1	
MINGO - SETAB 345KV CKT 1	
MOORE COUNTY INTERCHANGE - POTTER COUNTY INTERCHANGE 230KV CKT 1	
MOORE COUNTY INTERCHANGE EAST BUS 115KV SWITCHED SHUNT	
NEWHART 230 - PLANT X STATION 230KV CKT 1	
NEWHART 230 - POTTER COUNTY INTERCHANGE 230KV CKT 1	

Contingency	Mitigation
OKLAUNION - TUCO INTERCHANGE 345KV CKT 1	
OKLAUNION 345KV SWITCHED SHUNT	
P12:115:LCEC:W56.1.HOBBG.LE-LVN	
P12:115:SPS:T04.1.DFSMTH.CASTRO	
P12:115:SPS:T13.1.TAYLOR.WHOBBS	
P12:115:SPS:T14.1.MADDOX.WBENDR	
P12:115:SPS:T38.1.POTJCT.WIPP	
P12:115:SPS:T53.1.NICHLS.KIRBY	
P12:115:SPS:T54.1.KIRBY.SHM(520)	
P12:115:SPS:T59.1.CARGIL.CURRY	
P12:115:SPS:T66.1.RNDALL.HAPPY	
P12:115:SPS:T67.1.HAPPY.KRESS	
P12:115:SPS:V29.1.NICHLS.KNGSMLL	
P12:115:SPS:W08.1.HITCH.LASLEY	
P12:138:AEPW:REDROCKRD4:WTH_JCT4	
P12:138:AEPW:S.W.S.-4:L.E.S.-4	
P12:138:AEPW:SHAM4WT:CHILD4WT	
P12:138:WFEC:MSL03	
P12:138:WFEC:MSL14	
P12:230:AEPW:ELKCITY6:SWEETWT6	
P12:230:AEPW-SPS:SWEETWT6:WHEELER 6	
P12:230:SPS:K43.1.PRNGLE.HARR_E	
P12:345:SPS:J07.1.FINN.HITCH	
P12:345:SPS:J14.1.EDDY.XRDS	
P12:345:SPS:J15.1.XRDS.TOLK	
P12:69:AEPW:NWMEMPH2:CHLDR2WT	
PALO DURO SUB - RANDALL COUNTY INTERCHANGE 115KV CKT 1	
PLANT X STATION - TOLK STATION EAST 230KV CKT 2	
PLANT X STATION - TOLK STATION WEST 230KV CKT 1	
POTTER COUNTY INTERCHANGE (WAUK 90343-A) 345/230/13.2KV TRANSFORMER CKT 1	
PRINGLE INTERCHANGE - SPEARMAN INTERCHANGE 115KV CKT 1	
STATELINE INTERCHANGE - STLN-DEMARC6 230KV CKT 1	
STLN-DEMARC6 - SWEETWATER 230KV CKT 1	
SWISHER COUNTY INTERCHANGE 230KV SWITCHED SHUNT	
TATONGA7 345.00 - WOODWARD DISTRICT EHV 345KV CKT 1	
TATONGA7 345.00 - WOODWARD DISTRICT EHV 345KV CKT 2	
THISTLE7 345.00 - WOODWARD DISTRICT EHV 345KV CKT 1	
THISTLE7 345.00 - WOODWARD DISTRICT EHV 345KV CKT 2	
TOLK STATION (ABBXNL844501) 345/230/13.2KV TRANSFORMER CKT 1	
TOLK STATION EAST - TUCO INTERCHANGE 230KV CKT 1	
TUCO INTERCHANGE - YOAKUM_345 345.00 345KV CKT 1	
TUCO INTERCHANGE (GE M1022338) 345/230/13.2KV TRANSFORMER CKT 1	
TUCO INTERCHANGE (SIEM 8743066) 345/230/13.2KV TRANSFORMER CKT 2	
WAVERLY7 345.00 - WOLF CREEK 345KV CKT 1	

Table 8.19 Group 6 Cluster ERIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
BUSHLAND INTERCHANGE - POTTER COUNTY INTERCHANGE 230KV CKT 1	329.05	101.1848	System Intact	Mitigated by voltage collapse upgrades and higher queued upgrades
COCHRAN INTERCHANGE - G15-014T 115.00 115KV CKT 1	120.9	107.0929	System Intact	
CRAWFISH_DR 345.00 (CRAWFISH_DR) 345/230/13.2KV TRANSFORMER CKT 1	560.0	160.0401	CRAWFISH_DR 345.00 - TUCO INTERCHANGE 345KV CKT 1	
CRAWFISH_DR2230.00 - TUCO INTERCHANGE 230KV CKT 1	547.0	187.3884	CRAWFISH_DR 345.00 - TUCO INTERCHANGE 345KV CKT 1	
CURRY COUNTY INTERCHANGE - DEAF SMITH REC-#20 115KV CKT 1	96.0	100.9705	System Intact	
DEAF SMITH COUNTY INTERCHANGE - PLANT X STATION 230KV CKT 1	318.7	114.5202	System Intact	
G15079_T 230.00 - YOAKUM COUNTY INTERCHANGE 230KV CKT 1	350.57	134.1501	P12:345:SPS:J15.1.XRDS.TOLK	
GRAPEVINE INTERCHANGE - NICHOLS STATION 230KV CKT 1	318.7	100.3944	System Intact	
Harrington Station East Bus - POTTER COUNTY INTERCHANGE 230KV CKT 1	350.57	117.9679	CHERRY1 - POTTER COUNTY INTERCHANGE 230KV CKT 1	
JOHNSON DRAW - TAYLOR SWITCHING STATION 115KV CKT 1	160.0	135.4951	G15079_T 230.00 - YOAKUM COUNTY INTERCHANGE 230KV CKT 1	
TUCO INTERCHANGE (GE M1022338) 345/230/13.2KV TRANSFORMER CKT 1	644.0	101.527	TUCO INTERCHANGE (SIEM 8743066) 345/230/13.2KV TRANSFORMER CKT 2	
ANDREWS 3115.00 - National Enrichment Plant Sub 115KV CKT 1	525.0	103.7801	G14_012T 230.00 - HOBBS INTERCHANGE 230KV CKT 1	Hobbs – Andrews 230kV (345kV Built) conversion to operate at 345kV, Install two new Andrews 345/115/13kV Transformers
ANDREWS 6230.00 (FROM BORDEN) 230/115/13.2KV TRANSFORMER CKT 2	168.0	157.1727	G14_012T 230.00 - HOBBS INTERCHANGE 230KV CKT 1	
ANDREWS 6230.00 (FROM MIDLAND) 230/115/13.2KV TRANSFORMER CKT 1	168.0	156.4035	G14_012T 230.00 - HOBBS INTERCHANGE 230KV CKT 1	
G14_012T 230.00 - HOBBS INTERCHANGE 230KV CKT 1	422.0	123.2858	ANDRWSXFMR12	
LE-WEST_SUB3115.00 - LEA COUNTY REC-LOVINGTON	143.4	104.4352	System Intact	

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
INTERCHANGE 115KV CKT 1				
COCHRAN INTERCHANGE - G15-014T 115.00 115KV CKT 1	120.9	107.0929	System Intact	Tolk - Yoakum Tap 230/115 kV Substation and Transformer
CIMARRON - MINCO 345KV CKT 1	956.0	119.3308	G14-057T 345.00 - SUNNYSIDE 345KV CKT 1	Updated rating is sufficient for mitigation
DRINKARD SUB - DRINKARD TAP 115KV CKT 1	103.0	192.3608	G14_012T 230.00 - HOBBS INTERCHANGE 230KV CKT 1	Re-conductor/Rebuild approximately 2 miles of 115kV
DRINKARD SUB - National Enrichment Plant Sub 115KV CKT 1	160.0	137.953	G14_012T 230.00 - HOBBS INTERCHANGE 230KV CKT 1	Re-conductor/Rebuild approximately 7.5 miles of 115kV
DRINKARD TAP - WEST HOBBS SWITCHING STATION 115KV CKT 1	160.0	111.4781	G14_012T 230.00 - HOBBS INTERCHANGE 230KV CKT 1	Re-conductor/Rebuild approximately 12.5 miles of 115kV
JAL SUB - TEAGUE SUB 115KV CKT 1	120.0	102.5845	G14_012T 230.00 - HOBBS INTERCHANGE 230KV CKT 1	Re-conductor/Rebuild approximately 10 miles of 115kV (NTC)
National Enrichment Plant Sub - TARGA 3115.00 115KV CKT 1	120.0	112.107	ANDREWS 6230.00 - HOBBS INTERCHANGE 230KV CKT 1	Re-conductor/Rebuild approximately 4 miles of 115kV (NTC)
National Enrichment Plant Tap - TARGA 3115.00 115KV CKT 1	120.0	101.9469	ANDREWS 6230.00 - HOBBS INTERCHANGE 230KV CKT 1	Re-conductor/Rebuild approximately 3 miles of 115kV (NTC)
National Enrichment Plant Tap - TEAGUE SUB 115KV CKT 1	120.0	109.244	G14_012T 230.00 - HOBBS INTERCHANGE 230KV CKT 1	Re-conductor/Rebuild approximately 7 miles of 115kV (NTC)
TOLK STATION (ABBXNL844501) 345/230/13.2KV TRANSFORMER CKT 1	560.0	101.5617	CROSSROADS 7345.00 - TOLK STATION 345KV CKT 1	Install second 345/230/13kV transformer

The table below summarizes constraints and associated mitigations assignable to incremental ERIS steady state voltage.

Table 8.20 Group 6 Cluster ERIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
MCLEAN RURAL SUB 115KV	0.933339	0.90	1.05	OKLAUNION - TUCO INTERCHANGE 345KV CKT 1	Shamrock Capacitor Bank(s)
SHAMROCK 115KV	0.92956	0.90	1.05	OKLAUNION - TUCO INTERCHANGE 345KV CKT 1	
SHAMROCK 69KV	0.88574	0.90	1.05	OKLAUNION - TUCO INTERCHANGE 345KV CKT 1	

In addition to the ERIS constraint mitigations, several NRIS thermal and voltage constraints were observed for system-intact and single-contingency (N-1) conditions. The table below summarizes constraints and associated mitigations assignable to those requests that elect NRIS.

Table 8.21 Group 6 Cluster NRIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
CARLISLE INTERCHANGE - LP-DOUD_TP 3115.00 115KV CKT 1	160.0	117.8623	WOLFFORTH INTERCHANGE (WH 7001668) 230/115/13.2KV TRANSFORMER CKT 1	Constraints are mitigated with ERIS upgrades
CRAWFISH_DR 345.00 (CRAWFISH_DR) 345/230/13.2KV TRANSFORMER CKT 1	560.0	130.0882	CRAWFISH_DR 345.00 - TUCO INTERCHANGE 345KV CKT 1	
CRAWFISH_DR2230.00 - TUCO INTERCHANGE 230KV CKT 1	547.0	131.7626	CRAWFISH_DR 345.00 - TUCO INTERCHANGE 345KV CKT 1	
LP-DOUD_TP 3115.00 - SP-WOLF_TP 3115.00 115KV CKT 1	180.0	106.5466	LUBBOCK SOUTH INTERCHANGE - WOLFFORTH INTERCHANGE 230KV CKT 1	
SP-WOLF_TP 3115.00 - YUMA INTERCHANGE 115KV CKT 1	180.0	100.2424	LUBBOCK SOUTH INTERCHANGE - WOLFFORTH INTERCHANGE 230KV CKT 1	
TERRY COUNTY INTERCHANGE - WOLFFORTH INTERCHANGE 115KV CKT 1	153.97	104.2732	TUCO INTERCHANGE - YOAKUM_345 345.00 345KV CKT 1	
CIMARRON - MINCO 345KV CKT 1	956.0	100.42	G14-057T 345.00 - SUNNYSIDE 345KV CKT 1	Updated rating is sufficient for mitigation
CARLISLE INTERCHANGE (WH XHS70711) 230/115/13.2KV TRANSFORMER CKT 1	168.0	107.0453	CARLISLE INTERCHANGE - WOLFFORTH INTERCHANGE 230KV CKT 1	Replace transformer
Hitchland Interchange (H TB80155502) 345/230/13.2KV TRANSFORMER CKT 1	644.0	100.572	Hitchland Interchange (SIEM 8743067) 345/230/13.2KV TRANSFORMER CKT 2	Install third transformer
Hitchland Interchange (SIEM 8743067) 345/230/13.2KV TRANSFORMER CKT 2	644.0	102.9676	Hitchland Interchange (H TB80155502) 345/230/13.2KV TRANSFORMER CKT 1	
LUBBOCK POWER & LIGHT-HOLLY PLANT (SHIH T101039) 230/69/13.5KV TRANSFORMER CKT 1	224.0	104.4463	LUBBOCK POWER & LIGHT-SOUTHEAST - LUBBOCK SOUTH INTERCHANGE 230KV CKT 1	Install second transformer
TUCO INTERCHANGE (ENRCO 136401) 230/115/13.2KV TRANSFORMER CKT 1	288.0	119.2294	TUCO INTERCHANGE (ENRCO 136401) 230/115/13.2KV TRANSFORMER CKT 2	Crawfish 115kV substation expand, install 230/115kV transformer, and loop in TUCO – Hale County 115kV
TUCO INTERCHANGE (ENRCO 136401) 230/115/13.2KV TRANSFORMER CKT 2	288.0	119.2294	TUCO INTERCHANGE (ENRCO 136401) 230/115/13.2KV TRANSFORMER CKT 1	

The table below summarizes constraints and associated mitigations assignable to incremental NRIS steady state voltage.

Table 8.22 Group 6 Cluster NRIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Currently none that are incremental to ERIS non-convergence, ERIS thermal, and NRIS thermal mitigations					

8.1.6 CLUSTER GROUP 7 (SOUTHWESTERN OKLAHOMA AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The ERIS thermal constraints were observed for system-intact and single-contingency (N-1) conditions. The table below summarizes constraints and associated mitigations. The table below summarizes constraints and associated mitigations.

Table 8.23 Group 7 Cluster ERIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
CIMARRON - MINCO 345KV CKT 1	956.0	100.5565	G14-057T 345.00 - SUNNYSIDE 345KV CKT 1	Updated rating are sufficient for mitigation

The table below summarizes constraints and associated mitigations assignable to incremental ERIS steady state voltage.

Table 8.24 Group 7 Cluster ERIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Currently none that are incremental to ERIS thermal mitigations					

The table below summarizes constraints and associated mitigations assignable to those requests that elect NRIS.

Table 8.25 Group 7 Cluster NRIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
Currently none				

The table below summarizes constraints and associated mitigations assignable to incremental NRIS steady state voltage.

Table 8.26 Group 7 Cluster NRIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Currently none that are incremental to ERIS thermal mitigations					

8.1.7 CLUSTER GROUP 8 (NORTH OKLAHOMA/SOUTH CENTRAL KANSAS AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

Several ERIS thermal and voltage constraints were observed for system-intact and single-contingency (N-1) conditions. The table below summarizes constraints and associated mitigations. The table below summarizes constraints and associated mitigations. Potential voltage collapse is inferred from non-convergence.

Table 8.27 Group 8 Cluster ERIS Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
CANEYRV7 345.00 - NEOSHO 345KV CKT 1	766	99	System Intact	Recently replaced terminal equipment will mitigate this constraint. Cost allocation updated to remove current study project cost assignment.
CHILOCCO4 138.00 - MIDLTNT4 138.00 138KV CKT 1	106.0	184.0574	System Intact	Re-conductor/Rebuild 3.45 miles of 138kV
FARBER - SUMNER COUNTY NO. 10 BELLE PLAIN 138KV CKT 1	160.0	118.7439	System Intact	Re-conductor/Rebuild 10.3 miles of 138kV
FARBER - SUMNER COUNTY NO. 10 BELLE PLAIN 138KV CKT 1	160.0	167.0358	MIDLTNT4 138.00 - PECKHAM TAP 138KV CKT 1	
G15063_T 345.00 - MATHWSN7 345.00 345KV CKT 1	1192.0	118.6256	NORTHWEST - SPRING CREEK 345KV CKT 1	Higher queued upgrade mitigates this constraint
G15063_T 345.00 - WOODRING 345KV CKT 1	956.0	117.2428	NORTHWEST - SPRING CREEK 345KV CKT 1	Replace structures
KILDARE4 - WHITE EAGLE 138KV CKT 1	222.0	107.7514	HUNTERS7 345.00 - WOODRING 345KV CKT 1	Re-conductor/Rebuild 11 miles of 138kV
NORTHWEST - SPRING CREEK 345KV CKT 1	1195.0	100.6786	G15063_T 345.00 - MATHWSN7 345.00 345KV CKT 1	Replace terminal equipment
OSAGE - WEBB CITY TAP 138KV CKT 1	152.0	100.6804	System Intact	Re-conductor/Rebuild 22 miles of 138kV
OSAGE - WHITE EAGLE 138KV CKT 1	191.0	100.4115	CONTINENTAL EMPIRE - WHITE EAGLE 138KV CKT 1	Re-conductor/Rebuild 3 miles of 138kV

The table below summarizes constraints and associated mitigations assignable to incremental ERIS steady state voltage.

Table 8.28 Group 8 Cluster ERIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
TC-ROCK 138KV	0.887068	0.93	1.05	SUMNER 4 - TIMBJCT4 138KV CKT 1	Sumner – Viola 138kV (NTC)
TIMBJCT4 138KV	0.887576	0.93	1.05	SUMNER 4 - TIMBJCT4 138KV CKT 1	
CANEYRV7 345.00 345KV	0.924033	0.95	1.05	LACYGNE - WAVERLY7 345.00 345KV CKT 1	SPP & SPP TO determined mitigation is achieved by model adjustments to local switchable reactors and local wind farms providing required power factor ranges.
ELKRVR17 345.00 345KV	0.930383	0.95	1.05	LACYGNE - WAVERLY7 345.00 345KV CKT 1	
LATHAMS7 345.00 345KV	0.930345	0.95	1.05	LACYGNE - WAVERLY7 345.00 345KV CKT 1	
NEOSHO 345KV	0.947824	0.95	1.05	LACYGNE - WAVERLY7 345.00 345KV CKT 1	

In addition to the ERIS constraint mitigations, several NRIS thermal constraints were observed for system-intact and single-contingency (N-1) conditions. The table below summarizes constraints and associated mitigations assignable to those requests that elect NRIS.

Table 8.29 Group 8 Cluster NRIS Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
FARBER - SUMNER COUNTY NO. 10 BELLE PLAIN 138KV CKT 1	160.0	99.3	G15-015T 138.00 - MDFRDTP4 138.00 138KV CKT 1	Constraints are mitigated with ERIS upgrades
OSAGE - WEBB CITY TAP 138KV CKT 1	152.0	119.8299	CLEVELAND - G15066_T 345.00 345KV CKT 1	
CLEAVELAND - CLEVLND 4 138.00 138KV CKT Z1	371.0	123.6455	CLEVELAND - TULSA NORTH 345KV CKT 1	Replace bus tie breaker with three breaker ring and upgrade associated terminal equipment
CLEAVELAND - SILVER CITY 138KV CKT 1	174.0	107.892	CLEVELAND - TULSA NORTH 345KV CKT 1	Higher queued upgrade mitigates this constraint
CLEVELAND (CLVAUTO1) 345/138/13.8KV TRANSFORMER CKT 1	494.0	99.8	CLEVELAND - TULSA NORTH 345KV CKT 1	Install second 345/138/13kV transformer
FAIRFAX TAP - SHIDLER 138KV CKT 1	211.0	102.1664	CLEVELAND - G15066_T 345.00 345KV CKT 1	Re-conductor/Rebuild 2.5 miles of 138kV
FAIRFAX TAP - WEBB CITY TAP 138KV CKT 1	211.0	102.1702	CLEVELAND - G15066_T 345.00 345KV CKT 1	Re-conductor/Rebuild 0.5 miles of 138kV
KINZE - MCELROY 138KV CKT 1	222.0	102.4282	CLEVELAND - G15066_T 345.00 345KV CKT 1	Re-conductor/Rebuild 2 miles of 138kV

The table below summarizes constraints and associated mitigations assignable to incremental NRIS steady state voltage.

Table 8.30 Group 8 Cluster NRIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Currently none that are incremental to ERIS thermal, voltage, and NRIS thermal mitigations					

8.1.8 CLUSTER GROUP 9 (NEBRASKA AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

Several ERIS thermal and voltage constraints were observed for system-intact and single-contingency (N-1) conditions. The table below summarizes constraints and associated mitigations. The table below summarizes constraints and associated mitigations. Potential voltage collapse is inferred from non-convergenced

NPPD and BEPC will need to perform further stability analysis for the Gentleman and Laramie area interconnect requests. This additional analysis could require additional mitigation by means of new transmission.

Table 8.31 Group 9 Cluster ERIS Non-Convergence Constraints

Contingency	Mitigation
BANNER_CO 345.00 - G1623&1629-T345.00 345KV CKT 1	In addition to high queued assigned upgrades the following new upgrades are required for group 9 potential voltage collapse: 1) Advance Gentleman – Thedford – Holt 345kV project 2) Build approximately 140 miles of new 345kV from Banner County – Keystone 3) Build approximately 30 miles of second 345kV circuit from Keystone – Gentleman
FT THOMPSON - FTTHOM2-LNX3345.00 345KV CKT Z	
FTTHOM2-LNX3345.00 - GRPRAR2-LNX3345.00 345KV CKT 1	
FTTHOMPSON-GRANDPRAIRIE-TLINE-REACTOR-CKT1	
G1623&1629-T345.00 - SIDNEY2-LNX3345.00 345KV CKT 1	
GR ISLD-LNX3345.00 - GRAND ISLAND 345KV CKT Z	
GR ISLD-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1	
KEYSTONE - SIDNEY1-LNX3345.00 345KV CKT 1	
LARAMIE RIVER - STEGALL 345KV CKT 1	
SIDNEY - SIDNEY1-LNX3345.00 345KV CKT Z	
SIDNEY - SIDNEY2-LNX3345.00 345KV CKT Z	
SIDNEY-KEYSTONE-TLINE-REACTORS-CKT1	

Table 8.32 Cluster ERIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
GERALD GENTLEMAN STATION - OGALLALA 230KV CKT 1	320.0	110.8242	GERALD GENTLEMAN STATION - KEYSTONE 345KV CKT 1	Build approximately 30 miles of second 345kV circuit from Keystone – Gentleman
KEYSTONE (KEYSTONE T1) 345/115/13.8KV TRANSFORMER CKT 1	336.0	103.7167	GERALD GENTLEMAN STATION - KEYSTONE 345KV CKT 1	
GR ISLD-LNX3345.00 - GRAND ISLAND 345KV CKT Z	720.0	119.4505	FT THOMPSON - FTTHOM2-LNX3345.00 345KV CKT Z	Advance Gentleman – Thedford – Holt 345kV project (NTC)
GR ISLD-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1	720.0	118.985	FT THOMPSON - FTTHOM2-LNX3345.00 345KV CKT Z	
OGALLALA - SIDNEY 230KV CKT 1	320.0	127.7388	SIDNEY-KEYSTONE-TLINE-REACTORS-CKT1	Build approximately 140 miles of new 345kV from Banner County – Keystone
SIDNEY - SIDNEY TRANSFORMER 230KV CKT 1	400.0	122.5383	SIDNEY-KEYSTONE-TLINE-REACTORS-CKT1	
SIDNEY (SDQ KV2A) 345/230/13.8KV TRANSFORMER CKT 1	480.0	99.9	SIDNEY - SIDNEY1-LNX3345.00 345KV CKT Z	

The table below summarizes constraints and associated mitigations assignable to incremental ERIS steady state voltage.

Table 8.33 Group 9 Cluster ERIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
ATWOOD 115KV	0.89625	0.90	1.05	G16-050-TAP 345.00 - POST ROCK 345KV CKT 1	Install 10 Mvars of Capacitor Bank(s) at Atwood 115kV as current study upgrade
ATWOOD SWITCH 115KV	0.896664	0.90	1.05	G16-050-TAP 345.00 - POST ROCK 345KV CKT 1	
BVERVLLY 115.00 115KV	0.89886	0.90	1.05	G16-050-TAP 345.00 - POST ROCK 345KV CKT 1	
LUDELL 3 115.00 115KV	0.897028	0.90	1.05	G16-050-TAP 345.00 - POST ROCK 345KV CKT 1	
LUDELLT3 115.00 115KV	0.897045	0.90	1.05	G16-050-TAP 345.00 - POST ROCK 345KV CKT 1	
MCDONLD3 115.00 115KV	0.899428	0.90	1.05	G16-050-TAP 345.00 - POST ROCK 345KV CKT 1	
NORTH ATWOOD 115KV	0.896563	0.90	1.05	G16-050-TAP 345.00 - POST ROCK 345KV CKT 1	
ONEOK 3 115.00 115KV	0.898709	0.90	1.05	G16-050-TAP 345.00 - POST ROCK 345KV CKT 1	

The table below summarizes constraints and associated mitigations assignable to those requests that elect NRIS.

Table 8.34 Group 9 Cluster NRIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
Currently None				

The table below summarizes constraints and associated mitigations assignable to incremental NRIS steady state voltage.

Table 8.35 Group 9 Cluster NRIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Currently None					

8.1.9 CLUSTER GROUP 10 (SOUTHEAST OKLAHOMA/NORTHEAST TEXAS AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C. No new requests in this group.

8.1.10 CLUSTER GROUP 12 (NORTHWEST ARKANSAS AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The table below summarizes ERIS constraints and associated mitigations. The table below summarizes constraints and associated mitigations.

Table 8.36 Group 12 Cluster ERIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
Currently none				

The table below summarizes constraints and associated mitigations assignable to incremental ERIS steady state voltage.

Table 8.37 Group 12 Cluster ERIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Currently none that are incremental to ERIS thermal mitigations					

The table below summarizes constraints and associated mitigations assignable to those requests that elect NRIS.

Table 8.38 Group 12 Cluster NRIS Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
NEOSHO - SUB 452 - RIVERTON 161KV CKT 1	209.0	102.0388	System Intact	Re-conductor/Rebuild 28 miles of 161kV
NEOSHO - SUB 452 - RIVERTON 161KV CKT 1	223.0	114.4813	LITCHFIELD - SUB 349 - ASBURY 161KV CKT 1	

The table below summarizes constraints and associated mitigations assignable to incremental NRIS steady state voltage.

Table 8.39 Group 12 Cluster NRIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Currently none that are incremental to NRIS thermal mitigations					

8.1.11 CLUSTER GROUP 13 (NORTHEAST KANSAS/NORTHWEST MISSOURI AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C. No new constraints were observed.

Table 8.40 Group 13 Cluster ERIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
Current none				

The table below summarizes constraints and associated mitigations assignable to incremental ERIS steady state voltage.

Table 8.41 Group 13 Cluster ERIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Current none					

The table below summarizes constraints and associated mitigations assignable to NRIS steady state thermal.

Table 8.42 Group 13 Cluster NRIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
Currently none				

The table below summarizes constraints and associated mitigations assignable to incremental NRIS steady state voltage.

Table 8.43 Group 13 Cluster NRIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Current none					

8.1.12 CLUSTER GROUP 14 (SOUTH CENTRAL OKLAHOMA AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

Several ERIS thermal and voltage constraints were observed for system-intact and single-contingency (N-1) conditions. The table below summarizes constraints and associated mitigations. The table below summarizes constraints and associated mitigations.

Table 8.44 Group 14 Cluster ERIS Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
CLAYTON - SARDIS 138KV CKT 1	98.0	108.1484	CANADIAN RIVER () 345/138/13.8KV TRANSFORMER CKT 1	Recently completed Re-conductor/rebuild approximately 3.8 miles of 138kV.
ENOWILT - LONE OAK 138KV CKT 1	98.0	103.3477	CANADIAN RIVER () 345/138/13.8KV TRANSFORMER CKT 1	Recently completed re-conductor/rebuild approximately 0.3 miles of 138kV.
ENOWILT - SARDIS 138KV CKT 1	98.0	104.9117	CANADIAN RIVER () 345/138/13.8KV TRANSFORMER CKT 1	Recently completed re-conductor/rebuild approximately 22.4 miles of 138kV.

The table below summarizes constraints and associated mitigations assignable to incremental ERIS steady state voltage.

Table 8.45 Group 14 Cluster ERIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Current none					

The table below summarizes constraints and associated mitigations assignable to those requests that elect NRIS.

Table 8.46 Group 14 Cluster NRIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
Currently None				

The table below summarizes constraints and associated mitigations assignable to incremental NRIS steady state voltage.

Table 8.47 Group 14 Cluster NRIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Current none					

8.1.13 CLUSTER GROUP 15 (EASTERN SOUTH DAKOTA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The table below summarizes constraints and associated mitigations. The table below summarizes constraints and associated mitigations.

GEN-2016-017 was also analyzed in Group 16 due to its close electrical location to other current study group 16 requests.

Table 8.48 Group 15 Cluster ERIS Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
SPLIT ROCK - WHITE 345KV CKT 1	720.0	121.1556	System Intact	Updated rating is sufficient for constraint mitigation

The table below summarizes constraints and associated mitigations assignable to incremental ERIS steady state voltage.

Table 8.49 Group 15 Cluster ERIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Current none					

The table below summarizes constraints and associated mitigations assignable to NRIS steady state thermal.

Table 8.50 Group 15 Cluster NRIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
Current none				

The table below summarizes constraints and associated mitigations assignable to incremental NRIS steady state voltage.

Table 8.51 Group 15 Cluster NRIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Current none					

8.1.14 CLUSTER GROUP 16 (WESTERN NORTH DAKOTA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

Several ERIS thermal and voltage constraints were observed for system-intact and single-contingency (N-1) conditions. The table below summarizes constraints and associated mitigations. The table below summarizes constraints and associated mitigations.

Table 8.52 Group 16 Cluster ERIS Non-Convergence Constraints

Contingency	Mitigation
FORBES - ROSEAU 500KV CKT 1	Mitigation subject to Affected System Review and analysis.
RIEL - ROSEAU 500KV CKT 1	
ROSEAU - ROSEAUM 2 500.00 500KV CKT 1	

Table 8.53 Group 16 Cluster ERIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
BUFFALO - JAMESTOWN 345KV CKT 1	705.0	104.97	System Intact	Mitigation subject to Affected System Review and analysis.
ELLENDALE - OAKES 230KV CKT 1	319.0	100.3304	System Intact	

The table below summarizes constraints and associated mitigations assignable to incremental ERIS steady state voltage.

Table 8.54 Group 16 Cluster ERIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
G16-017-TAP 345.00 345KV	1.105048	0.90	1.05	FTTHOM1-LNX3345.00 - G16-017-TAP 345.00 345KV CKT 1	GEN-2016-017 POI Substation reactor required

The table below summarizes constraints and associated mitigations assignable to those requests that elect NRIS.

Table 8.55 Group 16 Cluster NRIS Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
BUFFALO - JAMESTOWN 345KV CKT 1	705	101.2066	System Intact	Mitigation subject to Affected System Review and analysis
BUFFALO - JAMESTOWN 345KV CKT 1	705	116.6	CNTSHNT3 345.00 - PRAIRIE3 345.00 345KV CKT 1	
FARGO - SHEYNNE 230KV CKT 1	342.0	139.1369	BUFFALO - JAMESTOWN 345KV CKT 1	Higher queued, DPP-2016-FEB-West Phase 1 mitigation
GLENHAM - L3 HAWDON 230KV CKT 1	210.0	106.141	FT THOMPSON - FTTHOM1-LNX3345.00 345KV CKT Z	Replace terminal equipment
GLENHAM - WHITLOK 230KV CKT 1	260.0	102.4597	GEN-2016-017TAP-FTTHOMPSONREACTOR-FTTHOMPSON-CKT1	Updated rating is sufficient for constraint mitigations
HURON (BD KU2A) 345/230/13.8KV TRANSFORMER CKT 1	400.0	114.5418	FT THOMPSON - FTTHOM1-LNX3345.00 345KV CKT Z	Updated rating sufficient for mitigation

The table below summarizes constraints and associated mitigations assignable to incremental NRIS steady state voltage.

Table 8.56 Group 16 Cluster NRIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
GRPRAR 345KV	0.809257	0.90	1.05	WATERTN-LNX3345.00 - WATERTOWN 345KV CKT Z	Advance R-Plan
GRAND ISLAND 345KV	0.891388	0.90	1.05	WATERTOWN-WHITE-TLINE-REACTOR-CKT1	

8.1.15 CLUSTER GROUP 17 (WESTERN SOUTH DAKOTA)

New requests for this study group as well as prior-queued requests are listed in Appendix C. No new constraints were observed.

Table 8.57 Group 17 Cluster ERIS Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
Currently none				

The table below summarizes constraints and associated mitigations assignable to incremental ERIS steady state voltage.

Table 8.58 Group 17 Cluster ERIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Currently none					

The table below summarizes constraints and associated mitigations assignable to those requests that elect NRIS.

Table 8.59 Group 17 Cluster NRIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
Currently none				

The table below summarizes constraints and associated mitigations assignable to incremental NRIS steady state voltage.

Table 8.60 Group 17 Cluster NRIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Currently none					

8.1.16 CLUSTER GROUP 18 (EASTERN NORTH DAKOTA)

New requests for this study group as well as prior-queued requests are listed in Appendix C. No new constraints were observed.

Table 8.61 Group 18 Cluster ERIS Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
Currently none				

The table below summarizes constraints and associated mitigations assignable to incremental ERIS steady state voltage.

Table 8.62 Group 18 Cluster ERIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Currently none					

The table below summarizes constraints and associated mitigations. The table below summarizes constraints and associated mitigations.

Table 8.63 Group 18 Cluster NRIS Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
Currently none				

The table below summarizes constraints and associated mitigations assignable to incremental NRIS steady state voltage.

Table 8.64 Group 18 Cluster NRIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
Currently none					

8.2 *STAND-ALONE SCENARIO*

The Stand-Alone Scenario considers the Base Case as well as all generating facilities (and with respect to (3) below, any identified Network Upgrades associated with such higher-queued interconnection) that, on the date the DISIS is commenced:

1. are directly connected to the Transmission System;
2. are interconnection to Affected Systems and may have an impact on the Interconnection Request;
3. have a pending higher-queued Interconnection Request to interconnect to the Transmission System or have executed an Interconnection Facilities Study Agreement; and
4. have no Interconnection Queue Position but have executed a GIA or requested that an unexecuted GIA be filed with FERC.

Constraints and associated mitigations for each Interconnection Request are summarized in the table below. Details are contained in Appendix G1-T and Appendix G1-V. Cost allocation for the Stand-Alone Scenario is found in Appendix E1.

Limited Operation results are listed below. While these results are based on the criteria listed in GIP 8.4.3, the Interconnection Customer may request additional scenarios for Limited Operation based on higher-queued Interconnection Requests not being placed in service. All of these amounts listed are based on SPP limitations and do not account for limitations on Affected Systems.

Table 8.65 Limited Operation Results

Group Number	Request	Available MW Before Mitigation	Most-Limiting Constraint	Mitigation
	GEN-2015-095	0	DGRASSE4 138.00 - ROSE_VALLEY 138.00 138KV CKT 1	DeGrasse 345/138kV Project
	GEN-2016-003	248.4	None	
	GEN-2016-020	0	DGRASSE4 138.00 - ROSE_VALLEY 138.00 138KV CKT 1	DeGrasse 345/138kV Project
	GEN-2016-045	501.4	None	
	GEN-2016-047	469	None	
	GEN-2016-057	501.4	None	
Group 2	GEN-2015-082	200	None	
	GEN-2016-070	0	BUSHLAND INTERCHANGE - POTTER COUNTY INTERCHANGE 230KV CKT 1	Replace line traps at both terminal (higher queued upgrades)
Group 3	GEN-2016-005	ERIS – 0	Non-convergence constraints listed in Section 8 Group 3 tables	Build Beaver Co – Clark Co 345kV
		NRIS – 0		
	GEN-2016-016	0		
		0		
	GEN-2016-046	0		
	GEN-2016-049	0		
Group 4	GEN-2016-067	73.6	None	
Group 6	GEN-2015-041	ERIS – 5	None	
		NRIS – 0	CARLISLE INTERCHANGE - LP-DOUD_TP 3115.00 115KV CKT 1	Rebuild Carlisle – LP-Doud 115kV CKT 1.
	GEN-2016-015	0	Non-convergence constraints listed in Section 8 Group 6 tables	1) Oklaunion 150Mvar Capacitor Bank(s) and +/-100Mvar SVC 2) Border +300Mvar SVC and 300Mvars of capacitor bank(s) 3) Build approximately 64 miles of new 345kV from Crawfish Draw – Tolk 4) Build approximately 115 miles of new 345kV from Tolk – Potter County
	GEN-2016-056	0		
	GEN-2016-062	0		
	GEN-2016-069	0		
Group 7	GEN-2016-037	300	None	
	GEN-2016-051	9.8	None	
Group 8	GEN-2016-009	29	None	
	GEN-2016-022	151.8	None	
	GEN-2016-031	1.5	None	
	GEN-2016-032	ERIS – 200	None	
		NRIS – 200	None	
	GEN-2016-048	ERIS – 0	FARBER - SUMNER COUNTY NO. 10 BELLE PLAIN 138KV CKT 1	Rebuild Farber – Belle Plains 138kV CKT 1
		NRIS – 0	Limited by ERIS	
	GEN-2016-060	0	FARBER - SUMNER COUNTY NO. 10 BELLE PLAIN 138KV CKT 1	Rebuild Farber – Belle Plains 138kV CKT 1
	GEN-2016-061	0	G15063_T 345.00 - WOODRING 345KV CKT 1	Replace structures
	GEN-2016-068	0	G15063_T 345.00 - WOODRING 345KV CKT 1	Replace structures

Group Number	Request	Available MW Before Mitigation	Most-Limiting Constraint	Mitigation
	GEN-2016-071	0	CHILOCCO4 138.00 - MIDLTNT4 138.00 138KV CKT 1	Rebuild Chilocco – Middleton 138kV
	GEN-2016-073	220	None	
Group 9	GEN-2015-089	0	Non-convergence constraints listed in Section 8 Group 9 tables	R- Plan (Gentleman – Thedford – Holt 345kV).
	GEN-2016-021	300	None	
	GEN-2016-023	0	Non-convergence constraints listed in Section 8 Group 9 tables	Build Banner Co – Keystone 345kV CKT 1, Keystone – GGS 345kV CKT 2, and R-Plan
	GEN-2016-029	0		
	GEN-2016-043	230	None	
	GEN-2016-050	250.7	None	
	GEN-2016-075	0	Non-convergence constraints listed in Section 8 Group 9 tables	R- Plan (Gentleman – Thedford – Holt 345kV).
Group 12	GEN-2016-013	ERIS – 10	None	
		NRIS – 0	NEOSHO - SUB 452 - RIVERTON 161KV CKT 1	Rebuild Neosho – Riverton 161kV CKT 1
	GEN-2016-014	ERIS – 10	None	
		NRIS – 0	NEOSHO - SUB 452 - RIVERTON 161KV CKT 1	Rebuild Neosho – Riverton 161kV CKT 1
Group 14	GEN-2015-036	303.6	None	
	GEN-2016-028	100	None	
	GEN-2016-030	100	None	
	GEN-2016-063	200	None	
Group 15	GEN-2016-017	250.7	None	
Group 16	GEN-2016-004	ERIS – 201.6		
		NRIS – 0	GLENHAM - L3 HAWDON 230KV CKT 1 and Low voltage at GRPRAR 345KV GRAND ISLAND 345KV	Rplan and Replace terminal equipment
	GEN-2016-052	3.3	None	
	GEN-2016-053	3.3	None	
Group 17	GEN-2016-054	3.4	None	
Group 18	GEN-2016-007	100.05	None	

8.3 CURTAILMENT AND SYSTEM RELIABILITY

In no way does this study guarantee operation for all periods of time. It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list and cannot account for every operational situation. Because of this, it is likely that the Customer(s) may be required to reduce their generation output to 0 MW, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

9 STABILITY & SHORT CIRCUIT ANALYSIS

A stability and short-circuit analysis was conducted for each Interconnection Request using modified versions of the 2015 MDWG Models 2016 winter, 2017 summer, and 2025 summer peak dynamic cases[3]. The stability analysis assumes that all upgrades identified in the power flow analysis are in-service unless otherwise noted in the individual group stability study.

For each group, the interconnection requests are studied at 100% nameplate output while the other groups are dispatched at 20% output for Variable Energy Resource (VER) requests and 100% output for other requests. The output of the Interconnection Customer's facility is offset in each model by a reduction in output of existing online SPP generation. Each Interconnection Request is studied in a Stand Alone scenario in addition to the cluster scenario.

A synopsis is included for each group. The detailed stability study for each group can be found in the Appendices.

A preliminary short-circuit analysis was performed for this study and mitigations were identified below. The short-circuit analysis will be refined in the Interconnection Facilities Study and any additional required upgrades and cost assignment will be identified at that time.

9.1 POWER FACTOR REQUIREMENTS SUMMARY

Power factor requirements are listed in the table below by cluster group. In addition, some Interconnection Requests may have requirements for reactors under low-wind conditions as identified in the detailed reports found in the Appendices.

Group	Request	Size (MW)	Generator Model	Point of Interconnection	Minimum Lagging Power Factor	Minimum Leading Power Factor
1	GEN-2015-095	176	Vestas V110	Tap on Mooreland to Noel Switch 138kV (G15-095T)	0.95	0.95
1	GEN-2016-003	248.4	Vestas GS V126 3.45MW	Tap on Hitchland to Woodward 345kV (G16-003-TAP)	0.95	0.95
1	GEN-2016-020	150	Vestas V110 VCSS 2.0MW	Mooreland 138 kV (520999)	0.95	0.95
1	GEN-2016-045	500	GE 2.3MW	Mathewson 345 kV (515497)	0.95	0.95
1	GEN-2016-057	500	GE 2.3MW	Mathewson 345 kV (515497)	0.95	0.95
2	GEN-2015-082	200.0	GE 2.0MW	Tap on Woodward (515375) to Beaver (515554) 345kV (G11-14-TAP, 560000)	0.95	0.95
2	GEN-2016-070	5.3MW Uprate (Total 84.8MW)	GE 1.6MW	Martin Switching Station 115kV (523928)	0.95	0.95

[3]Short Circuit analysis performed only on the 2017 and 2025 Summer Peak seasonal model. Group 6 and Group 15 Stability Analyses also include 2020 Summer and Winter Peak seasons.

Group	Request	Size (MW)	Generator Model	Point of Interconnection	Minimum Lagging Power Factor	Minimum Leading Power Factor
3	GEN-2016-005	150	Vestas V110 2.0MW wind	GEN-2016-005-TAP 345 kV (Tap on Clark County – Thistle 345 kV line)	0.95	0.95
3	GEN-2016-016	78.2	GE 2.3MW wind	North Kinsley 115 kV	0.95	0.95
3	GEN-2016-046	299	GE 2.3MW wind	GEN-2016-046-TAP 345 kV (Tap on Clark County – Ironwood 345 kV line)	0.95	0.95
3	GEN-2016-049	310.2	Vestas V117 GS 3.3MW wind	GEN-2016-049-TAP 345 kV (Tap on GEN-2013-010 Tap/Post Rock – Spearville 345 kV line)	0.95	0.95
6	ASGI-2016-001	2.5	Envision E110 2.5MW (wind)	Wolfforth 115kV (526524)	0.95	0.95
6	ASGI-2016-002	0.35 uprate to ASGI-2015-002; total power = 2.53MW)	GE 2.53MW (584723)(wind)	Hurlwood Substation 69/12/74IV) [Yuma Interchange 115/69kV (526469)]	0.95	0.95
6	ASGI-2016-004	10	3 x Alstom 3.2MW/4 x Renewtech 100kW	Palo Duro 115kV (524530)	0.95	0.95
6	GEN-2016-015	100	TMEIC 1.667NW PV inverters (solar)	Andrews 230kV (528604)	0.95	0.95
6	GEN-2016-056	200	GE 2.0MW (wind)	Carlisle 230 kV (526161)	0.95	0.95
6	GEN-2016-062	250.7	GE 2.3MW (wind)	Andrews 230kV (528604)	0.95	0.95
6	GEN-2016-069	31.35	Hanwha 3.8MW & Hanwha 0.95MW	Chaves County 115kV (527482)	0.95	0.95
7	GEN-2016-037	300	Vestas V110 2.0MW (587233)	Tap Chisholm (511553) – Gracemont (515800) 345kV, (G16-037-TAP, 560078)	0.95	0.95
7	GEN-2016-051	9.8MW uprate to GEN-2003-022/GEN-2004-020 (total = 156.8MW)	G.E. 1.6MW (579363)	Tap Clinton Junction (511534) – Weatherford Southeast (511536) 138kV, (WTH WF 138kV, 511506)	0.95	0.95
8	GEN-2016-022	151.8	Vestas V126 3.45MW (wind; 587163)	Ranch Road 345kV (515576)	0.95	0.95
8	GEN-2016-031	1.5MW uprate of GEN-2015-001(total = 201.3MW)	Vestas V126 3.3MW (wind; 584453)	Ranch Road 345kV (515576)	0.95	0.95
8	GEN-2016-032	200	Vestas V110 2MW (wind; 587213)	Tap Marshall (514733)- Cottonwood Creek (514827) 138kV, (G16-032-TAP, 560077)	0.95	0.95

Group	Request	Size (MW)	Generator Model	Point of Interconnection	Minimum Lagging Power Factor	Minimum Leading Power Factor
8	GEN -2016-048	74	Sunny Central 2940 2.94MW (solar; 587333)	Sooner 138kV (514802)	0.95	0.95
8	GEN-2016-060	25.3	G.E. 2.3MW (wind)	Belle Plain 138kV (533063)	0.95	0.95
8	GEN-2016-061	250.7	GE 2.3 MW (wind; 587413)	Tap Woodring (514715) – Sooner (514803) 345kV (G16-061-TAP, 560084)	0.95	0.95
8	GEN-2016-068	250	GE 2.0MW (wind; 587463)	Woodring 345kV (514715)	0.95	0.95
8	GEN-2016-071	200.1	GE 2.3MW (wind; 587483)	Chilocco 138kV (521198)	0.95	0.95
8	GEN-2016-073	220	GE 2.0MW (wind; 587503)	Tap on Thistle (539801) to Wichita (532796) 345kV, ckt1&2 (Buffalo Flats 345kV; 560033)	0.95	0.95
9	GEN-2015-089	200	GE 2.0MW	Utica 230kV (652526)	0.95	0.95
9	GEN-2016-021	300	Vestas V110 VCSS 2.0MW (wind)	Hoskins 345kV (640266)	0.95	0.95
9	GEN-2016-023	150.5	GE 2.0MW and 1.79MW wind (587093, 587095)	Tap Sidney (659426) - Laramie River (659131) 345kV (587090)	0.95	0.95
9	GEN-2016-029	150.5	GE 2.3MW and 1.79MW wind	Tap Sidney (659426) - Laramie River (659131) 345kV (587090)	0.95	0.95
9	GEN-2016-043	230	GE 2.3MW wind (587283)	Hoskins 345kV (640226)	0.95	0.95
9	GEN-2016-050	250.7	GE 2.3MW wind (587353)	Axtell (640065)-Post Rock (530583) 345 kV (560082)	0.95	0.95
9	GEN-2016-075	50	Vestas V110 VCSS 2.0MW wind	Tap Ft. Thompson-Hope County 345 kV (Grand Prarie, 652532)	0.95	0.95
14	GEN-2015-036	303.6	Siemens 2.3 MW (wind)	PSO Johnston County 345 kV	0.95	0.95
14	GEN-2016-028	100	Vestas V110 VCSS 2.0 MW (wind)	Clayton 138 kV	0.95	0.95
14	GEN-2016-030	100	AE 500NX 0.5MW (solar)	Brown 138 kV	0.95	0.95
14	GEN-2016-063	200	Vestas V110 VCSS 2.0MW	Tap on Hugo to Sunnyside 345kV	0.95	0.95
15	GEN-2016-017	250.7	109 x G.E. 2.3 MW wind	Tap Fort Thompson (652806) – Leland Olds (659105) 345 kV, (G16-017-TAP, 560074)	0.95	0.95
16	GEN-2016-004	202	Vestas V136 3.6MW /Vestas V110 2.0MW	BEPC Leland Olds 230kV (659106)	0.95	0.95
16	GEN-2016-052	3.3 uprate to GI-0508 (total = 52.8MW)	GE 1.6MW wind	Hilken 230kV (652466)	0.95	0.95

Group	Request	Size (MW)	Generator Model	Point of Interconnection	Minimum Lagging Power Factor	Minimum Leading Power Factor
16	GEN-2016-053	3.3 uprate to GI-0615 (total = 52.8MW)	GE 1.6MW wind	Hilken 230kV (652466)	0.95	0.95
17	GEN-2015-089	200	GE 2.0MW wind	WAPA Utica Junction 230kV (652526)	0.95	0.95
17	GEN-2016-054	3.4 uprate (total = 54.4MW)	GE 1.6MW wind	Wessington Springs 230kV (652607)	0.95	0.95
18	GEN-2016-007	100.0	VESTAS V126 GS 3.45MW WIND	WAPA Valley City 115 kV (652454)	0.95	0.95

9.2 CLUSTER STABILITY AND SHORT-CIRCUIT SUMMARY

9.2.1 CLUSTER GROUP 1 (WOODWARD AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The Group 1 stability analysis for this area was performed by S&C Electric (S&C). With the new requests modeled, violations of voltage recovery criteria were observed. However, these violations were due to some modelling issues. Once the modelling issues were corrected, the voltage violations no longer existed.

Upgrades identified in the power flow analysis were also tested in the stability analysis. This was done to make sure that the power flow upgrades do not affect the stability of the system.

The consultant observed that GEN-2016-045 and GEN-2016-057 would require large reactors, 294-330 MVAR, to compensate for the line charging current from each approximate 300 miles long transmission lead to the POI. It is essential for the facility study of these requests to incorporate an electromagnetic transients (EMT) study to identifying an appropriate design of the reactive compensation.

With all previously-assigned and currently-assigned Network Upgrades placed in service, no violations were observed, including violations of low-voltage ride-through requirements, for the probable contingencies studied.

9.2.2 CLUSTER GROUP 2 (HITCHLAND AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The Group 2 stability analysis for this area was performed by SPP Staff (SPP). With the new requests modeled, violations of stability damping criteria and voltage recovery criteria were not observed. Upgrades identified in the power flow analysis were also tested in the stability analysis.

With all previously-assigned and currently-assigned Network Upgrades placed in service, no violations were observed, including violations of low-voltage ride-through requirements, for the probable contingencies studied.

9.2.3 CLUSTER GROUP 3 (SPEARVILLE AREA)

The Group 3 stability analysis was not performed again for this restudy. This group was not analyzed for this restudy and previously identified restudy results remain valid.

9.2.4 CLUSTER GROUP 4 (NORTHWEST KANSAS AREA)

The Group 4 stability analysis was not performed again for this restudy. This group was not analyzed for this restudy and previously identified restudy results remain valid.

9.2.5 CLUSTER GROUP 6 (SOUTH TEXAS PANHANDLE/NEW MEXICO AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The Group 6 stability analysis for this area was performed by MEPPI. With the new requests modeled, violations of stability damping criteria and voltage recovery criteria were observed. Upgrades identified in the power flow analysis were also tested in the stability analysis.

The consultant has determined the following needed upgrades:

- Build Crawfish Draw to Tolk 345 kV Circuit #1
- Build Tolk to Potter County 345 kV Circuit #1
- Build Potter County 345/230 kV Transformer #2
- Build Potter County to Grapevine to Chisholm 345 kV Circuit #1
- Add +300 Mvar SVC at Border 345 kV
    - 600 total capacitive Mvars at Border 345 kV (300 Mvar switchable capacitor banks modeled as 6 blocks of 50 Mvar
- Add +/- 100 Mvar SVC at Oklaunion 345 kV
- Add 250 Mvar to existing switchable capacitor bank at Oklaunion 345kV (this brings total to 440 Mvar)
- Build Woodward to Tatonga to Mathewson 345 kV Circuit #2
    - Required to be implemented in 16WP and 17SP
    - Line exists in 20WP, 20SP, and 25SP
- Build Chaves County to Price to CV Pine to Capitan 115 kV Circuit #1
    - Required to be implemented in 16WP and 17SP
    - Line exists in 20WP, 20SP, and 25SP
- Convert existing Andrews 230 kV substation and Hobbs to Andrews 230 kV circuit to 345 kV

In the 20WP season, under normal system dispatch, system instability exists for a fault that results in the loss of the Tuco to Oklaunion 345 kV line. For this reason, it is necessary to limit the total interconnection service in this area until all area generation scheduled for retirement has been realized.

With all previously-assigned and currently-assigned Network Upgrades placed in service, no violations were observed, including violations of low-voltage ride-through requirements, for the probable contingencies studied.

9.2.6 CLUSTER GROUP 7 (SOUTHWESTERN OKLAHOMA AREA)

The Group 7 stability analysis was not performed again for this restudy. This group was not analyzed for this restudy and previously identified restudy results remain valid.

9.2.7 CLUSTER GROUP 8 (NORTH OKLAHOMA/SOUTH CENTRAL KANSAS AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The Group 8 stability analysis for this area was performed by MEPPI. With the new requests modeled, violations of stability damping criteria and voltage recovery criteria were observed. Upgrades identified in the power flow analysis were also tested in the stability analysis.

The consultant has determined the following:

- Dispatch of shunt capacitors at TIMBJCT2 and UDALL_2 following the outage of the Belle Plaine (533063) – Farber (533042) 138kV line to mitigate steady-state voltage violations.
- Reduction of generation at GEN-2016-071 following prior outage of Middleton Tap to Peckham Tap 138 kV line to mitigate instability and generator tripping.

With all previously-assigned and currently-assigned Network Upgrades placed in service, no violations were observed, including violations of low-voltage ride-through requirements, for the probable contingencies studied.

9.2.8 CLUSTER GROUP 9 (NEBRASKA AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The Group 9 stability analysis for this area was performed by MEPPI. With the new requests modeled, violations of stability damping criteria and voltage recovery criteria were observed. Upgrades identified in the power flow analysis were also tested in the stability analysis.

The consultant has determined the following needed upgrades:

- Keystone to Banner County (G16-034 Tap) 345 kV circuit #1
- SPP R Plan (16WP and 17SP advancement)
    - Cherry County/Thedford 345/115/13.8 kV transformer
    - Gentleman to Cherry County 345 kV circuit #1
    - Holt County to Cherry County 345 kV circuit #1
- Gentleman to Keystone 345 kV circuit #2
- 10 Mvar capacitor bank at Atwood 115 kV (25SP only)

With all previously-assigned and currently-assigned Network Upgrades placed in service, no violations were observed, including violations of low-voltage ride-through requirements, for the probable contingencies studied.

9.2.9 CLUSTER GROUP 12 (NORTHWEST ARKANSAS AREA)

The Group 12 stability analysis was not performed again for this restudy. This group was not analyzed for this restudy and previously identified restudy results remain valid.

9.2.10 CLUSTER GROUP 13 (NORTHEAST KANSAS/NORTHWEST MISSOURI AREA)

The Group 13 stability analysis was not performed again for this restudy. This group was not analyzed for this restudy and previously identified restudy results remain valid.

9.2.11 CLUSTER GROUP 14 (SOUTH CENTRAL OKLAHOMA AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The Group 14 stability analysis for this area was performed by S&C. New requests for this study group as well as prior-queued requests are listed in Appendix C.

With the new requests modeled, violations of stability damping criteria and voltage recovery criteria were observed. Upgrades identified in the power flow analysis were also tested in the stability analysis.

The consultant's report noted issues that warrant further investigation in the Facilities Study:

- Generation Interconnection Request GEN-2016-030 (involving Power Electronics HEC-USsolar inverters) was tripping offline due to underfrequency during faults at and near the POI. Further investigations and discussions with SPP concluded that this was potentially a simulation numerical issue and thus the frequency relay at interconnection request GEN-2016-030 was deactivated. The manufacturer will need to verify this study finding prior to interconnection service being provided.

The consultant has determined the following:

- Reduction of generation at GEN-2015-036 following prior outage of JOHNCO 7 (514809) to PITTSB-7 (510907) line to mitigate instability and generator tripping.

With all previously-assigned and currently-assigned Network Upgrades placed in service, no violations were observed, including violations of low-voltage ride-through requirements, for the probable contingencies studied.

9.2.12 CLUSTER GROUP 15 (EASTERN SOUTH DAKOTA)

The Group 15 stability analysis was not performed again for this restudy. This group was not analyzed for this restudy and previously identified restudy results remain valid.

9.2.13 CLUSTER GROUP 16 (WESTERN NORTH DAKOTA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The Group 16 stability analysis for this area was performed by MEPPI. With the new requests modeled, violations of stability damping criteria and voltage recovery criteria were observed. Upgrades identified in the power flow analysis were also tested in the stability analysis.

The consultant has identified the following:

- Reduction of generation at GI1414GEN W0.6900 Unit 1 located at bus 659453 from 137 MW to 50 MW (16WP, 17SP, and 25SP) and switch off 109.6 Mvar line reactor at bus 659421 (17SP) following prior outage of Heart River 230 kV (659448) to Belfield 230 kV (652425) CKT 1 to mitigate instability and generator tripping

With all previously-assigned and currently-assigned Network Upgrades placed in service, no violations were observed, including violations of low-voltage ride-through requirements, for the probable contingencies studied.

9.2.14 CLUSTER GROUP 17 (WESTERN SOUTH DAKOTA)

The Group 17 stability analysis was not performed again for this restudy. This group was not analyzed for this restudy and previously identified restudy results remain valid.

9.2.15 CLUSTER GROUP 18 (EASTERN NORTH DAKOTA)

The Group 18 stability analysis was not performed again for this restudy. This group was not analyzed for this restudy and previously identified restudy results remain valid.

9.3 STAND-ALONE SCENARIO STABILITY SUMMARY

The Stand-Alone Scenario considers the Base Case as well as all generating facilities (and with respect to (3) below, any identified Network Upgrades associated with such higher-queued interconnection) that, on the date the DISIS is commenced:

1. are directly connected to the Transmission System;
2. are interconnection to Affected Systems and may have an impact on the Interconnection Request;
3. have a pending higher-queued Interconnection Request to interconnect to the Transmission System or have executed an Interconnection Facilities Study Agreement; and
4. have no Interconnection Queue Position but have executed a GIA or requested that an unexecuted GIA be filed with FERC.

Constraints and associated mitigations for each Interconnection Request are summarized in the Section 8.2. Details are contained in Appendix J. Cost allocation for the Stand-Alone Scenario is found in Appendix E1.

9.4 CURTAILMENT AND SYSTEM RELIABILITY

In no way does this study guarantee operation for all periods of time. It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list and cannot account for every operational situation. Because of this, it is likely that the Customer(s) may be required to reduce their generation output to 0 MW, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

10 CONCLUSION

The minimum cost of interconnecting all new generation interconnection requests included in this Definitive Interconnection System Impact Study is estimated at $1.4 Billion, not including the exceptions noted in Section 5.

Allocated costs for Network Upgrades and Transmission Owner Interconnection Facilities are listed in Appendix E and F. For Interconnection Requests that result in an interconnection to, or modification of, the transmission facilities of the Western-UGP (WAPA), a National Environmental Policy Act (NEPA) Environmental Review will be required. The Interconnection Customer will be required to execute an Environmental Review Agreement per Section 8.6.1 of the GIP.

These costs do not include the cost of upgrades of other transmission facilities listed in Appendix H which are Network Constraints. These interconnection costs do not include any cost of any Network Upgrades that are identified as required through the short circuit analysis. Potential over-duty circuit breakers capability will be identified by the Transmission Owner in the Interconnection Facilities Study.

Please note higher queued, MISO 2016-FEB-West Phase 2 analysis is not complete at this time. Depending on the results and mitigations assigned in MISO-2016-FEB-West Phase 2, SPP could require a restudy for Group 9, 15, 16, 17, and 18 due to higher queue study assumption changes.

Further refinement of total estimated interconnection costs will be provided, should the Interconnection Customer meet the requirements for acceptance and choose to move into the Interconnection Facilities Study following the posting of this DISIS. The Interconnection Facilities Study may include additional study analysis, additional facility upgrades not yet identified by this DISIS, such as circuit breaker replacements and affected system facilities, and further refinement of existing cost estimates.

The required interconnection costs listed in Appendices E, and F, and other upgrades associated with Network Constraints do not include all costs associated with the deliverability of the energy to final customers. These costs are determined by separate studies if the Customer submits a Transmission Service Request (TSR) through SPP's Open Access Same Time Information System (OASIS) as required by Attachment Z1 of the SPP Open Access Transmission Tariff (OATT).

11 APPENDICES

SPP Southwest Power Pool

DISIS-2016-002

Definitive Interconnection System Impact Study Report

Published August 20, 2018

By SPP Generator Interconnections Dept.

REVISION HISTORY

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
04/19/2018	SPP	Initial report issued.	Results for Cluster Groups 1, 2, 4, 10, 12, and 14.
			Results for Cluster Group 8.
5/22/2018	SPP	Report re-issued.	LOIS amounts updated for Cluster Group 4.
			One-line diagram for ASGI-2016-010 updated.
6/4/2018	SPP	Report re-issued.	1. Corrected total cluster upgrade costs in Sec. 5 and 10. 2. Changes affecting Group 8 a. Corrected the Contingency ID for VIOLA 7 345.00 - WICHITA 345KV CKT 1 in Table 8-8. b. Added 3 missing constraints in Table 8-9 for SILOAM CITY - SILOAM SPRINGS, SILOAM CITY – SILOAM SPRINGS TAP, and SILOAM SPRINGS TAP TRANSFORMER, updated costs in Appendix E and F, and constraints in Appendix G-T. c. Updated total cost for GRDA-GREC Tap in Appendix E and F.
6/17/2018	SPP	Report re-issued	Draft results for Cluster Group 6
7/16/2018	SPP	Report re-issued	Results for Cluster Groups 6, 7, 13, and 17. Model development description updated.
			Preliminary results for Cluster Groups 9, 15, and 16.
8/10/2018	SPP	Report re-issued	Identification of Group 8 and 13 requests requiring an Affected System Impact Study from AECI.

DATE OR VERSION NUMBER	AUTHOR	CHANGE DESCRIPTION	COMMENTS
8/20/2018	SPP	Report re-issued	Results for Cluster Groups 9, 15, and 16. Cost allocation for Groups 8,13, and GEN-2016-177

CONTENTS

1 INTRODUCTION

Pursuant to the Southwest Power Pool (SPP) Open Access Transmission Tariff (OATT), SPP has conducted this Definitive Interconnection System Impact Study (DISIS) for generation interconnection requests received during the DISIS Queue Cluster Window which closed on November 30, 2016. The customers will be referred to in this study as the DISIS Interconnection Customers. This DISIS analyzes the impact of interconnecting new generation totaling 15,938.10 MW to the SPP Transmission System. The interconnecting SPP Transmission Owners include:

- American Electric Power West (AEPW)
- Basin Electric Power Cooperative (BPEC)
- Grand River Dam Authority (GRDA)
- Kansas City Power and Light\KCP&L Greater Missouri Operations (KCPL)
- Midwest Energy (MIDW)
- Nebraska Public Power District (NPPD)
- Oklahoma Gas and Electric (OKGE)
- Omaha Public Power District (OPPD)
- Southwestern Public Service (SPS)
- Southwestern Power Administration (SWPA)*
- Western Area Power Administration (WAPA)
- Westar Energy, Inc. (WERE)
- Western Farmers Electric Cooperative (WFEC)

*SWPA is a SPP Contract Participant

The generation interconnection requests included in this System Impact Study are listed in 11.1 by queue number, amount, requested interconnection service type, area, requested interconnection point, proposed interconnection point, and the requested in-service date[1].

The primary objective of this DISIS is to identify the system constraints, transient instabilities, and over-dutied equipment associated with connecting the generation to the area transmission system. The Impact Study and other subsequent Interconnection Studies are designed to identify required Transmission Owner Interconnection Facilities, Network Upgrades and other Direct Assignment Facilities needed to inject power into the grid at each specific point of interconnection.

[1] The generation interconnection requests in-service dates may need to be deferred based on the required lead time for the Network Upgrades necessary. The Interconnection Customers that proceed to the Facility Study will be provided a new in-service date based on the completion of the Facility Study or as otherwise provided for in the GIP.

2 MODEL DEVELOPMENT (STUDY ASSUMPTIONS)

2.1 INTERCONNECTION REQUESTS INCLUDED IN THE CLUSTER

This DISIS includes all interconnection requests that were submitted during the DISIS Queue Cluster Window that met all of the requirements of the Generator Interconnection Procedures (GIP) that were in effect at the time this study commenced. Appendix A lists the interconnection requests that are included in this study.

2.2 AFFECTED SYSTEM INTERCONNECTION REQUEST

Affected System Interconnection Requests included in this study are listed in Appendix A with the "ASGI" prefix. Affected System Interconnection Requests were only studied in "cluster" scenarios.

2.3 PREVIOUSLY QUEUED INTERCONNECTION REQUESTS

The previous-queued requests included in this study are listed in Appendix B. In addition to the Base Case Upgrades, the previous-queued requests and associated upgrades were assumed to be in-service and added to the Base Case models. These requests were dispatched as Energy Resource Interconnection Service (ERIS) resources with equal distribution across the SPP footprint. Prior-queued requests that requested Network Resource Interconnection Service (NRIS) were also dispatched in separate NRIS scenarios sinking into the area of the interconnecting transmission owner.

2.4 DEVELOPMENT OF BASE CASES

POWER FLOW

The power flow models used for this study are based on the 2016-series Integrated Transmission Planning models used for the 2017 ITP-Near Term analysis. These models include:

- Year 1 2017 winter peak (17WP)
- Year 2 2018 spring (18G)
- Year 2 2018 summer peak (18SP)
- Year 5 2021 light (21L)
- Year 5 2021 summer (21SP)
- Year 5 2021 winter peak (21WP)
- Year 10 2026 summer peak (26SP)

DYNAMIC STABILITY

The dynamic stability models used for this study are based on the 2016-series SPP Model Development Working Group (MDWG) Models. These models include:

- Year 1 2017 winter peak (17WP)
- Year 2 2018 summer peak (18SP)
- Year 10 2026 summer peak (26SP)

SHORT CIRCUIT
The Year 2 and Year 10 dynamic stability summer peak models were used for short-circuit analysis.

BASE CASE UPGRADES
The facilities listed in the table below are part of the current SPP Transmission Expansion Plan, the Balanced Portfolio, or recently approved Priority Projects. These facilities have an approved Notification to Construct (NTC) or are in construction stages and were assumed to be in-service at the time of dispatch and added to the base case models. The DISIS Interconnection Customers have not been assigned advancement costs for the projects listed below.

The DISIS Interconnection Customers' Generation Facilities in-service dates may need to be delayed until the completion of the following upgrades. In some cases, the in-service date is beyond the allowable time a customer can delay. In this case, the Interconnection Customer may move forward with Limited Operation or remain in the DISIS Queue for additional study cycles. If, for some reason, construction on these projects is discontinued, additional restudies will be needed to determine the interconnection needs of the DISIS Interconnection Customers.

SPP Notification to Construct (NTC) ID	UID	Project Owner	Upgrade Name	Estimated Date of Upgrade Completion (EOC)
200223		OGE	Tatonga - Woodward District EHV 345 kV Ckt 2	3/1/2018
200223		OGE	Matthewson - Tatonga 345 kV Ckt 2	3/1/2018
200240		OGE	Chisholm - Gracemont 345 kV Ckt 1 (OGE)	3/1/2018
200255		AEP	Chisholm - Gracemont 345kV Ckt 1 (AEP)	3/1/2018
200255		AEP	Chisholm 345/230 kV Substation	3/1/2018
200255		AEP	Chisholm 230 kV	3/1/2018
200360		SPS	IMC #1 Tap - Livingston Ridge 115 kV Ckt 1 Rebuild	11/16/2018
200360		SPS	Intrepid West - Potash Junction 115 kV Ckt 1 Rebuild	11/16/2018
200360		SPS	IMC #1 Tap - Intrepid West 115 kV Ckt 1 Rebuild	11/16/2018
200360		SPS	Cardinal - Targa 115 kV Ckt 1 Rebuild	5/31/2018
200360	51250	SPS	National Enrichment Plant - Targa 115 kV Ckt 1	12/15/2018
200391	51528	OGE	DeGrasse 345 kV Substation	6/1/2019
200391	51529	OGE	DeGrasse 345/138 kV Transformer	6/1/2019
200391	51530	OGE	DeGrasse - Knob Hill 138 kV New Line	6/1/2019
200391	51569	OGE	DeGrasse 138 kV Substation (OGE)	6/1/2019
200220		NPPD	Cherry Co. (Thedford) - Gentleman 345 kV Ckt 1	10/1/2019
200220		NPPD	Cherry Co. (Thedford) Substation 345 kV	10/1/2019
200220		NPPD	Cherry Co. (Thedford) - Holt Co. 345 kV Ckt 1	10/1/2019
200220		NPPD	Holt Co. Substation 345 kV	10/1/2019
200253	50441	NPPD	Neligh 345/115 kV Substation	4/1/2018
200309		SPS	Hobbs 345/230 kV Ckt 1 Transformer	6/1/2018
200309		SPS	Hobbs - Yoakum 345 kV Ckt 1	6/1/2020
200395		SPS	Tuco - Yoakum 345 kV Ckt 1	6/1/2020
200395		SPS	Yoakum 345/230 kV Ckt 1 Transformer	6/1/2020
200256	50722	SPS	Chaves - Price 115 kV Ckt 1 Rebuild	1/30/2018

SPP Notification to Construct (NTC) ID	UID	Project Owner	Upgrade Name	Estimated Date of Upgrade Completion (EOC)
200256	50723	SPS	CV Pines - Price 115 kV Ckt 1 Rebuild	1/30/2018
200256	50724	SPS	Capitan - CV Pines 115 kV Ckt 1 Rebuild	1/30/2018
200282		SPS	China Draw - Yeso Hills 115 kV Ckt 1	6/1/2018
200282		SPS	Dollarhide - Toboso Flats 115 kV Ckt 1	6/1/2018
200309		SPS	Hobbs - Kiowa 345 kV Ckt 1	6/1/2018
200309		SPS	Kiowa 345 kV Substation	6/1/2018
200309		SPS	Kiowa - North Loving 345 kV Ckt 1	6/1/2018
200309		SPS	North Loving 345 kV Terminal Upgrades	6/1/2018
200309		SPS	China Draw - North Loving 345 kV Ckt 1	6/1/2018
200309		SPS	China Draw 345 kV Ckt 1 Terminal Upgrades	6/1/2018
200309		SPS	China Draw 345/115 kV Ckt 1 Transformer	6/1/2018
200309		SPS	North Loving 345/115 kV Ckt 1 Transformer	6/1/2018
200309		SPS	Kiowa 345/115 kV Ckt 1 Transformer	6/1/2018
200395	50924	SPS	Livingston Ridge 115 kV Substation Conversion	11/30/2017
200411		SPS	Livingston Ridge - Sage Brush 115 kV Ckt 1	6/1/2018
200309	50925	SPS	Sage Brush 115 kV Substation	12/16/2016
200309	50928	SPS	Largarto - Sage Brush 115 kV Ckt 1	12/15/2016
200309	50927	SPS	Lagarto 115 kV Substation	6/1/2018
200309	50951	SPS	Cardinal - Lagarto 115 kV Ckt 1	12/15/2016
200309	50967	SPS	Cardinal 115 kV Substation	12/15/2016
200411	50923	SPS	Ponderosa - Ponderosa Tap 115 kV Ckt 1	6/1/2017
200395		SPS	Canyon West – Dawn – Panda – Deaf Smith 115kV Ckt 1	12/15/2018
200369		SPS	Canyon East Sub – Randall County Interchange 115kV Ckt 1	12/31/2020
200359	11509	SPS	Carlisle 230/115kV transformer replacement	3/27/2018
200309		SPS	Hobbs – Yoakum – TUCO 345kV project	6/1/2018
200395		SPS	Terry County – Wolfforth 115kV Ckt 1 terminal equipment replacement	6/1/2018
200391		OGE	DeGrasse 345/138kV project	6/1/2019
200396		WFEC	DeGrasse 345/138kV project	12/31/2019
200395		SPS	Harrington East – Potter 230kV Ckt 1 terminal equipment replacement	6/1/2019
200228		WERE	Viola 345/138kV project	6/1/2018
200228		MKEC	Viola 345/138kV project	6/1/2018
200395		SPS	Seminole 230/115kV transformer Ckt 1 & 2 replacement	5/15/2018
200262		SPS	Yoakum County Interchange 230/115kV transformer Ckt 1 & 2 replacement	6/1/2019

CONTINGENT UPGRADES

The following facilities do not yet have approval. These facilities have been assigned to higher-queued interconnection customers. These facilities have been included in the models for this study and are assumed to be in service. This list may not be all-inclusive. The DISIS Interconnection Customers, at this time, do not have cost responsibility for these facilities but may later be assigned cost if higher-queued customers terminate their Generation Interconnection Agreement or withdraw from the interconnection queue. The DISIS Interconnection Customer Generation Facilities in-service dates may need to be delayed until the completion of the following upgrades.

Assigned Study	Upgrade Name	Estimated Date of Upgrade Completion (EOC)
DISIS-2010-002	Twin Church - Dixon County 230kV Line Upgrade	11/1/2018
DISIS-2010-002	Buckner - Spearville 345 kV Ckt 1 Terminal Upgrades	Complete 7/20/2017
DISIS-2011-001	Hoskins - Dixon County 230kV Line Upgrade	11/1/2018
DISIS-2014-002	Plant X - Tolk 230kV rebuild circuit #1	5/31/2018
DISIS-2014-002	Plant X - Tolk 230kV rebuild circuit #2	5/31/2018
DISIS-2014-002	TUCO Interchange 345/230kV CKT 1 Replacement	6/1/2018
DISIS-2015-001	(NRIS Only) Renfrow – Renfrow 138kV circuit #1 rebuild.	9/25/2017
DISIS-2015-001	Oklaunion 345kV Reactive Power	TBD
DISIS-2015-002	Beaver County 345kV Reactive Power Support Install +100Mvar SVC at Beaver County Substation.	TBD
DISIS-2015-002	Border - Chisholm 345kV CKT 1 & 2	TBD
DISIS-2015-002	Bushland - Potter County 230kV CKT 1	TBD
DISIS-2015-002	Carlisle 115/69/13kV Transformer CKT 1	TBD
DISIS-2015-002	Chisholm Substation Upgrade 345kV	TBD
DISIS-2015-002	Cleo Corner - Cleo Plant Tap 138kV CKT 1	TBD
DISIS-2015-002	Cleveland - Silver City 138kV CKT 1	TBD
DISIS-2015-002	Cornville Tap - Naples Tap 138kV CKT 1	TBD
DISIS-2015-002	Crawfish Draw 345/230kV Substation Upgrade Taps TUCO – Border 345kV, TUCO – Oklaunion 345kV, and TUCO – Swisher 230kV Build 345/230/13kV transformer	TBD
DISIS-2015-002	Crawfish Draw - Border 345kV CKT 2	TBD
DISIS-2015-002	Daglum - Dickinson 230kV CKT 1	TBD
DISIS-2015-002	Dickinson 230/115/13.8kV CKT 2	TBD
DISIS-2015-002	Gavins Point - Yankton Junction 115kV CKT 1	TBD
DISIS-2015-002	GEN-2015-063 Tap - Mathewson 345kV CKT 1	TBD
DISIS-2015-002	Grapevine - Wheeler 230kV CKT 1	TBD
DISIS-2015-002	Naples Tap - Payne 138kV CKT 1	TBD
DISIS-2015-002	Norge - Southwest Station 138kV CKT 1	TBD
DISIS-2015-002	Potter County Interchange 345/230/13kV Transformer circuit #2, build.	TBD
DISIS-2015-002	Albion - Petersburg - North Petersburg 115kV CKT 1	TBD
DISIS-2015-002	Wheeler - Sweetwater 230kV CKT 1	TBD
DISIS-2015-002	Woodward 345/138/13kV Transformer CKT 3	TBD
DISIS-2016-001	Andrews 345/115/13kV Transformer CKT 1 Replace 230/115kV transformer CKT 1 with 345/115kV transformer	TBD
DISIS-2016-001	Andrews 345/115/13kV Transformer CKT 2 Replace 230/115kV transformer CKT 2 with 345/115kV transformer	TBD
DISIS-2016-001	Andrews Substation Voltage Conversion Convert Andrews 230kV to 345kV	TBD
DISIS-2016-001	Atwood Capacitive Reactive Power Support Install 10 Mvars of Capicator Bank(s)	TBD
DISIS-2016-001	Banner County - Keystone 345kV CKT 1 Build approximately 140 of new 345kV from Banner County to Keystone. Banner County and Keystone Substation Work.	TBD
DISIS-2016-001	Beaver County - Clark County 345kV CKT 1 Build approximately 125 miles of new 345kV from Grapevine - Chisholm	TBD
DISIS-2016-001	BEPC Laramie Stability Limit Potential mitigation for BEPC Laramie Stability Limit	TBD
DISIS-2016-001	Border 345kV Reactive Power Support Install (6)Steps of 50Mvar Capacitor Bank(s) and +300Mvar SVC at Border Substation	TBD

Assigned Study	Upgrade Name	Estimated Date of Upgrade Completion (EOC)
DISIS-2016-001	Cleveland - Cleveland 138kV CKT Z1 NRIS only required upgrade: Replace bus tie breaker with a three breaker ring	TBD
DISIS-2016-001	Cleveland 345/138/13kV Transformer CKT 2 NRIS only required upgrade: Install second 345/138kV Transformer	TBD
DISIS-2016-001	Crawfish Draw 230/115/13kV Transformer CKT 1 NRIS only required upgrade: Build 115kV yard, re-terminate Hale County - TUCO 115kV, build 230/115/13kV transformer 1	TBD
DISIS-2016-001	Drinkard - Drinkard Tap 115kV CKT 1 Rebuild approximately 2 miles from Drinkard to Drinkard Tap	TBD
DISIS-2016-001	Drinkard Tap - West Hobbs 115kV CKT 1 Rebuild approximately 12.5 miles from Drinkard Tap to West Hobbs	TBD
DISIS-2016-001	Fairfax Tap - Shidler 138kV CKT 1 NRIS only required upgrade: Rebuild approximately 2.4 miles of 138kV	TBD
DISIS-2016-001	Farber - Belle Plains 138kV CKT 1 Rebuild approximately 10.3 miles of 138kV from Farber to Belle Plains	TBD
DISIS-2016-001	GEN-2015-063 Tap - Woodring 345kV CKT 1	TBD
DISIS-2016-001	Glenham - Mound City 230kV CKT 1 Uprate CT	TBD
DISIS-2016-001	Hitchland 345/230/13kV Transformer CKT 3 NRIS only required upgrade: Build third 345/230/13kV Transformer	TBD
DISIS-2016-001	Jamestown - Center 345kV CKT 1 MPC mitigation for Jamestown - Center 345kV	TBD
DISIS-2016-001	Keystone - Gentleman 345kV CKT 2 Build approximately 30 miles of new 345kV. Gentleman and Keystone Substation Work.	TBD
DISIS-2016-001	Kildare - White Eagle 138kV CKT 1 Rebuild approximately 11 miles of 138kV from Kildare to White Eagle	TBD
DISIS-2016-001	Kinsley - Pawnee 115kV CKT 1 Increase conductor clearance	TBD
DISIS-2016-001	Kinze - McElroy 138kV CKT 1 Rebuild approximately 2 miles of 138kV from Kinze to McElroy	TBD
DISIS-2016-001	Lubbock Holly 230/69/13kV CKT 2 NRIS only required upgrade: Install second Lubbock Holly 230/69/13kV Transformer	TBD
DISIS-2016-001	Middleton Tap - Chilocco 138kV CKT 1 Rebuild approximately 3.45 miles of 138kV from Middleton to Chilocco	TBD
DISIS-2016-001	National Enrichment Plant - Drinkard 115kV CKT 1 Rebuild approximately 7.5 miles from NEF Plant to Drinkard	TBD
DISIS-2016-001	Neosho - Riverton 161kV CKT 1 Rebuild approximately 28 miles of 161kV	TBD
DISIS-2016-001	Northwest - Spring Creek 345kV CKT 1 Replace terminal equipment	TBD
DISIS-2016-001	Oklaunion 345kV Reactive Power Support Incremental Upgrade Install 250Mvar capacitor banks and +/-100Mvar SVC at Oklaunion	TBD
DISIS-2016-001	Osage - Webb Tap 138kV CKT 1 Rebuild approximately 22 miles of 138kV from Osage to Webb City	TBD
DISIS-2016-001	Osage - White Eagle 138kV CKT 1 Rebuild approximately 3 miles of 138kV from Osage to White Eagle	TBD
DISIS-2016-001	Potter - Chisholm 345kV CKT 1 Build approximately 140 miles of new 345kV from Potter County – Chisholm	TBD
DISIS-2016-001	Shamrock 115kV Capacitor Bank	TBD

Assigned Study	Upgrade Name	Estimated Date of Upgrade Completion (EOC)
	Add 20Mvar of Capacitor Bank(s) at Shamrock 115kV	
DISIS-2016-001	Tolk - Crawfish Draw 345kV CKT 1 Build approximately 64 miles of 345kV from Tolk - Crawfish Draw.	TBD
DISIS-2016-001	Tolk - Potter County 345kV CKT 1 Build approximately 115 miles of 345kV from Tolk - Potter County	TBD
DISIS-2016-001	Tolk 345/230/13kV Transformer CKT 2 Build second 345/230/13kV transformer at Tolk	TBD
DISIS-2016-001	Webb City Tap - Fairfax Tap 138kV CKT 1 NRIS only required upgrade: Rebuild approximately 0.3 miles of 138kV. Costs included in Fairfax Tap - Shidler Upgrade	TBD

POTENTIAL UPGRADES NOT IN THE BASE CASE

Any potential upgrades that do not have a Notification to Construct (NTC) and are not explicitly listed within this report have not been included in the base case. These upgrades include any identified in the SPP Extra-High Voltage (EHV) overlay plan, or any other SPP planning study other than the upgrades listed above in the previous section.

REGIONAL GROUPINGS

The interconnection requests listed in Appendix A are grouped into fifteen (15) active regional groups based on geographical and electrical impacts. These groupings are shown in Appendix C.

To determine interconnection impacts, fifteen (15) different generation dispatch scenarios of the spring, summer, and winter base case models are developed to accommodate the regional groupings.

2.5 DEVELOPMENT OF ANALYSIS CASES

POWER FLOW

For Variable Energy Resources (VER) (solar/wind) in each power flow case, ERIS, is evaluated for the generating plants within a geographical area of the interconnection request(s) for the VERs dispatched at 100% nameplate of maximum generation. The VERs in the remote areas are dispatched at 20% nameplate of maximum generation in the spring, summer peak, and winter peak models. The VERs in the remote areas are dispatched at 10% nameplate of maximum generation in the light load models These projects are dispatched across the SPP footprint using load factor ratios.

Peaking units are not dispatched in the spring case, or in the "High VER" summer and winter peak cases. To study peaking units' impacts, the Year 1 winter peak and Year 2 summer peak, Year 5 summer and winter peaks, and Year 10 summer peak models are developed with peaking units dispatched at 100% of the nameplate rating and VERs dispatched at 20% of the nameplate rating. Each interconnection request is also modeled separately at 100% nameplate for certain analyses.

All generators (VER and peaking) that requested NRIS are dispatched in an additional analysis into the interconnecting Transmission Owner's (T.O.) area at 100% nameplate with ERIS only requests at 80% nameplate. This method allows for identification of network constraints that are common between regional groupings to have affecting requests share the mitigating upgrade costs throughout the cluster.

Each interconnection request is included in the power flow analysis models as an equivalent generator(s) dispatched at the applicable percentage of the requested service amount with 0.95 power factor capability. The facility modeling includes explicit representation of equivalent Generator Step-Up (GSU) and main project transformer(s) with impedance data provided in the interconnection request. Equivalent collector system(s) as well as transmission lead line(s) shorter than 20 miles are added to the power flow analysis models with zero impedance branches.

DYNAMIC STABILITY

For each group, all interconnection requests are dispatched at 100% nameplate output while the other groups are dispatched at 20% output for VERs and 100% output for thermal requests.

- Each study group includes system adjustments of dispatching, to maximum output, generation interconnected at the same or adjacent substations to a current study request within that group.
- Study Group 9 included an additional dispatch scenario to evaluate the Gerald Gentleman Station registered NERC flowgate #6006.
- Study Group 16 included system adjustments for the Miles City DC Tie, North Dakota – Canadian border – The phase shifting transformer to Saskatchewan Power (also known as B-10T), and reduction of WAPA (area 652) load and generation:
    - 2017 Winter Peak –
        - Miles City DC Tie– 200MW East to West transfer
        - B-10T – 65MW South to North transfer
    - 2018 Summer Peak –
        - Miles City DC Tie – 200MW East to West transfer
        - B-10T – 200MW North to South transfer
        - 1,100 MW reduction to load and generation (proxy for summer shoulder)
    - 2026 Summer Peak –
        - Miles City DC Tie – 200MW East to West transfer

Each interconnection request is included in the dynamic stability analysis models as an equivalent generator(s) dispatched at the applicable percentage of the aggregate generator nameplate capabilities provided in the interconnection request. The facility modeling includes explicit representation of equivalent Generator Step-up (GSU) transformer(s), equivalent collector system(s), main project transformer(s), and transmission lead line(s) with impedance data provided in the interconnection request.

SHORT CIRCUIT

The Year 2 and Year 10 dynamic stability Summer Peak models were used for this analysis.

3 IDENTIFICATION OF NETWORK CONSTRAINTS (SYSTEM PERFORMANCE)

3.1 THERMAL OVERLOADS

Network constraints are found by using PSS/E AC Contingency Calculation (ACCC) analysis with PSS/E MUST First Contingency Incremental Transfer Capability (FCITC) analysis on the entire cluster grouping dispatched at the various levels previously described.

For ERIS, thermal overloads are determined for system intact (n-0) greater than 100% of Rate A - normal and for contingency (n-n) greater than 100% of Rate B – emergency conditions.

The overloads are then screened to determine which interconnection requests have at least

- 3% Distribution Factor (DF) for system intact conditions (n-0),
- 20% DF upon outage-based conditions (n-n),
- or 3% DF on contingent elements that resulted in a non-converged solution.

Appropriate transmission reinforcements are identified to mitigate the constraints.

Interconnection Requests that requested NRIS are also studied in a separate NRIS analysis to determine if any constraint measured greater than or equal to a 3% DF. If so, these constraints are also assigned transmission reinforcements to mitigate the impacts.

3.2 VOLTAGE

For non-converged power flow solutions that are determined to be caused by lack of voltage support, appropriate transmission support will be identified to mitigate the constraint.

After all thermal overload and voltage support mitigations are determined; a full ACCC analysis is then performed to determine voltage constraints. The following voltage performance guidelines are used in accordance with the Transmission Owner local planning criteria.

SPP voltage criteria is applicable to all SPP facilities 69 kV and greater in the absence of more stringent criteria:

System Intact	Contingency
0.95 – 1.05 per unit	0.90 – 1.05 per unit

Areas and specific buses having more-stringent voltage criteria:

Areas/Facilities	System Intact	Contingency
AEPW – all buses EMDE High Voltage	0.95 – 1.05 per unit	0.92 – 1.05 per unit
WERE Low Voltage	0.95 – 1.05 per unit	0.93 – 1.05 per unit
WERE High Voltage	0.95 – 1.05 per unit	0.95 – 1.05 per unit
TUCO 230 kV Bus #525830	0.925 – 1.05 per unit	0.925 – 1.05 per unit
Wolf Creek 345 kV Bus #532797	0.985 – 1.03 per unit	0.985 – 1.03 per unit
FCS Bus #646251	1.001 – 1.047 per unit	1.001 – 1.047 per unit

First-Tier External Areas facilities 115 kV and greater.

Area	System Intact	Contingency
EES-EAI LAGN EES AMMO CLEC LAFA LEPA XEL MP SMMPA GRE OTP ALTW MEC MDU DPC ALTE	0.95 – 1.05 per unit	0.90 – 1.05 per unit
OTP-H (115kV+)	0.97 – 1.05 per unit	0.92 – 1.10 per unit
SPC	0.95 – 1.05 per unit	0.95 – 1.05 per unit

The constraints identified through the voltage scan are screened for the following for each interconnection request. 1) 3% DF on the contingent element and 2) 2% change in pu voltage. In certain conditions, engineering judgement was used to determine whether or not a generator had impacts to voltage constraints.

3.3 DYNAMIC STABILITY

Stability issues are considered for transmission reinforcement under ERIS. Generators that fail to meet low voltage ride-through requirements (FERC Order #661-A) or SPP's stability requirements for damping or dynamic voltage recovery are assigned upgrades such that these requirements can be met.

3.4 UPGRADES ASSIGNED

Thermal overloads that require transmission support to mitigate are discussed in Section 8 and listed in Appendix G-T (Cluster Analysis). Voltage constraints that may require transmission support are discussed in Section 8 and listed in Appendix G-V (Cluster Analysis). Constraints that are identified solely through the stability analysis are discussed in Section 9 and the appropriate appendix for the detailed stability study of that Interconnection Request. All of these upgrades are cost assigned in Appendix E and Appendix F.

Other network constraints not requiring transmission reinforcements are shown in Appendix H-T (Cluster Analysis). With a defined source and sink in a Transmission Service Request, this list of network constraints can be refined and expanded to account for all Network Upgrade requirements for firm transmission service. Additional constraints identified by multi-element contingencies are listed in Appendix I.

In no way does the list of constraints in Appendix G-T (Cluster Analysis) identify all potential constraints that guarantee operation for all periods of time. It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list and cannot account for every operational situation. Because of this, it is likely that the Customer(s) may be required to reduce their generation output to 0 MW, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

4 DETERMINATION OF COST ALLOCATED NETWORK UPGRADES

Cost Allocated Network Upgrades of Variable Energy Resources (VER) (solar/wind) generation interconnection requests are determined using the Year 2 spring model. Cost Allocated Network Upgrades of peaking units are determined using the Year 5 summer peak model. A PSS/E and MUST sensitivity analysis is performed to determine the DF with no contingency that each generation interconnection request has on each new upgrade. The impact each generation interconnection request has on each upgrade project is weighted by the size of each request. Finally, the costs due by each request for a particular project are then determined by allocating the portion of each request's impact over the impact of all affecting requests.

For example, assume that there are three Generation Interconnection requests, X, Y, and Z that are responsible for the costs of Upgrade Project '1'. Given that their respective PTDF for the project have been determined, the cost allocation for Generation Interconnection request 'X' for Upgrade Project 1 is found by the following set of steps and formulas:

Determine an impact factor for a given project for all responsible GI requests:

$$Request\ X\ Impact\ Factor\ on\ Upgrade\ Project\ 1 = PTDF(\%)(X) \times MW(X) = X1$$

$$Request\ Y\ Impact\ Factor\ on\ Upgrade\ Project\ 1 = PTDF(\%)(Y) \times MW(Y) = Y1$$

$$Request\ Z\ Impact\ Factor\ on\ Upgrade\ Project\ 1 = PTDF(\%)(Z) \times MW(Z) = Z1$$

Determine each request's Allocation of Cost for that particular project:

$$Request\ X's\ Project\ 1\ Cost\ Allocation\ (\$) = \frac{Network\ Upgrade\ Project\ 1\ Cost\ (\$) \times X1}{X1 + Y1 + Z1}$$

Repeat previous for each responsible GI request for each Project.

The cost allocation of each needed Network Upgrade is determined by the size of each request and its impact on the given project. This allows for the most efficient and reasonable mechanism for sharing the costs of upgrades.

4.1 CREDITS/COMPENSATION FOR AMOUNTS ADVANCED FOR NETWORK UPGRADES

Interconnection Customer shall be entitled to either credits or potentially incremental Long Term Congestion Rights (iLTCR), otherwise known as compensation, in accordance with Attachment Z2 of the SPP Tariff for any Network Upgrades, including any tax gross-up or any other tax-related payments associated with the Network Upgrades, and not refunded to the Interconnection Customer.

5 REQUIRED INTERCONNECTION FACILITIES

The requirement to interconnect the requested generation into the existing and proposed transmission systems in the affected areas of the SPP transmission footprint consist of the necessary cost allocated shared facilities listed in Appendix F by upgrade. The interconnection requirements for the cluster total an estimated **$6.212 billion**, not including the following costs.

- **Costs Not Included** – Group 9 & 15 evaluation of the registered NERC flowgates #5221, #6006, #6007, & #6008 identified transmission reinforcement upgrades.
- **Costs Not Included** – POI adjustment for interconnection requests GEN-2016-077 and GEN-2016-094, and associated changes to identified transmission reinforcement upgrades.
- **Costs Not Included** – Substantiated cost estimates for 765 kV Network Upgrades.
- **Costs Not Included** – Costs on Affected Systems for Associated Electric Cooperative Inc. (AECI), East River Electric Power Cooperative, Inc (EREC), Mid-Continent Independent System Operator (MISO), and Minnkota Power Cooperative, Inc (MPC).
- **Costs Not Included** –Particular Interconnection Facilities observing instability in the transient stability analysis due to Interconnection Facilities configuration or Interconnection Customer provided dynamic model settings and parameters. Please refer to Appendix E for requests that are identified as requiring further review or costs for Interconnection Facilities.

Interconnection Facilities specific to each interconnection request are listed in Appendix E. A preliminary one-line diagram for each request is listed in Appendix D.

For an explanation of how required Network Upgrades and Interconnection Facilities were determined, refer to the section on "Identification of Network Constraints."

5.1 FACILITIES ANALYSIS

The interconnecting Transmission Owner for each Interconnection Request has provided its preliminary analysis of required Transmission Owner Interconnection Facilities and the associated Network Upgrades, shown in Appendix D. This analysis was limited only to the expected facilities to be constructed by the Transmission Owner at the Point of Interconnection. These costs are included in the one-line diagrams in Appendix D and also listed in Appendix E and F as combined "Interconnection Costs". If the one-lines and costs in Appendix D have been updated by the Transmission Owner's Interconnection Facilities Study, those costs will be noted in the appendix. These costs will be further refined by the Transmission Owner as part of the Interconnection Facilities Study. Any additional Network Upgrades identified by this DISIS beyond the Point of Interconnection are defined and estimated by either the Transmission Owner or by SPP. These additional Network Upgrade costs will also be refined further by the Transmission Owner within the Interconnection Facilities Study.

5.2 ENVIRONMENTAL REVIEW

For Interconnection Requests that result in an interconnection to, or modification to, the transmission facilities of the Western-UGP, a National Environmental Policy Act (NEPA) Environmental Review will be required. The Interconnection Customer will be required to execute an Environmental Review Agreement per Section 8.6.1 of the GIP.

6 AFFECTED SYSTEMS COORDINATION

The following procedures are in place to coordinate with Affected Systems.

- Impacts on Associated Electric Cooperative Inc. (AECI) – For any observed violations of thermal overloads on AECI facilities, AECI has been notified by SPP to evaluate the violations for impacts on its transmission system.
- Impacts on Midcontinent Independent System Operator (MISO) – Per SPP's agreement with MISO, MISO will be contacted and provided a list of interconnection requests that proceed to move forward into the Interconnection Facilities Study Queue. MISO will then evaluate the Interconnection Requests for impacts and will be in contact with affected Interconnection Customers. For potential impacts see Appendix H-T – Affected System and Appendix H-V – Affected System
- Impacts on Minnkota Power Cooperative, Inc (MPC) – MPC will be contacted and provided a list of interconnection requests that proceed to move forward into the Interconnection Facilities Study Queue. MPC will then evaluate the Interconnection Requests for impacts. For potential impacts see Appendix H-T – Affected System and Appendix H-V – Affected System
- Impacts to other affected systems – For any observed violations of thermal overloads or voltage constraints, SPP will contact the owner of the facility for further information.

7 POWER FLOW ANALYSIS

7.1 POWER FLOW ANALYSIS METHODOLOGY

The ACCC function of PSS/E is used to simulate single element and special (i.e., breaker-to-breaker, multi-element, etc.) contingencies in portions or all of the modeled control areas of SPP, as well as, other control areas external to SPP and the resulting scenarios analyzed. Single element and multi-element contingencies are evaluated.

7.2 POWER FLOW ANALYSIS

A power flow analysis is conducted for each Interconnection Customer's facility using modified versions of the Year 1 winter peak season, the Year 2 spring, Year 2 summer peak season, Year 5 summer and winter peak seasons, and Year 10 summer peak seasonal models. The output of the Interconnection Customer's facility is offset in each model by a reduction in output of existing online SPP generation. This method allows the request to be studied as an ERIS request. Certain requests that are also pursuing NRIS have an additional analysis conducted for displacing resources in the interconnecting Transmission Owner's balancing area.

8 POWER FLOW RESULTS

8.1 CLUSTER SCENARIO

The Cluster Scenario considers the Base Case as well as all Interconnection Requests in the DISIS Study Queue and all generating facilities (and with respect to (3) below, any identified Network Upgrades associated with such higher-queued interconnection) that, on the date the DISIS is commenced:

1. are directly connected to the Transmission System;
2. are interconnection to Affected Systems and may have an impact on the Interconnection Request;
3. have a pending higher-queued Interconnection Request to interconnect to the Transmission System; and
4. have no Interconnection Queue Position but have executed a GIA or requested that an unexecuted GIA be filed with FERC.

Constraints and associated mitigations for each Interconnection Request are summarized below. Details are contained in Appendix G-T and Appendix G-V. Cost allocation for the Cluster Scenario is found in Appendix E.

CLUSTER GROUP 1 (WOODWARD AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

Several ERIS and NRIS thermal constraints were observed for single-contingency (N-1) and multi-contingency (P1, P2, etc.) conditions. The table below summarizes constraints and associated mitigations.

Table 8-1 Group 1 Cluster ERIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
DOVER SW - HENESSEY 138KV CKT 1	191	105.28	CRESENT - TWIN LAKES 138KV CKT 1	Terminal equipment

In addition to the ERIS constraint mitigations, several NRIS thermal and voltage constraints were observed for system-intact and single-contingency (N-1) conditions. The table below summarizes constraints and associated mitigations assignable to those requests that elect NRIS.